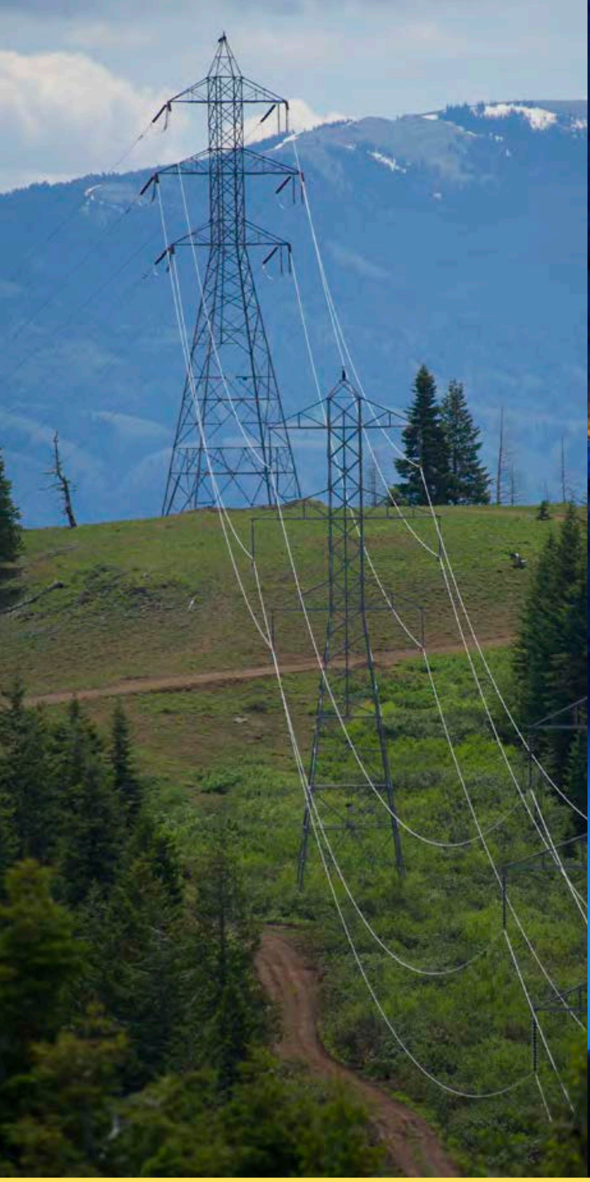

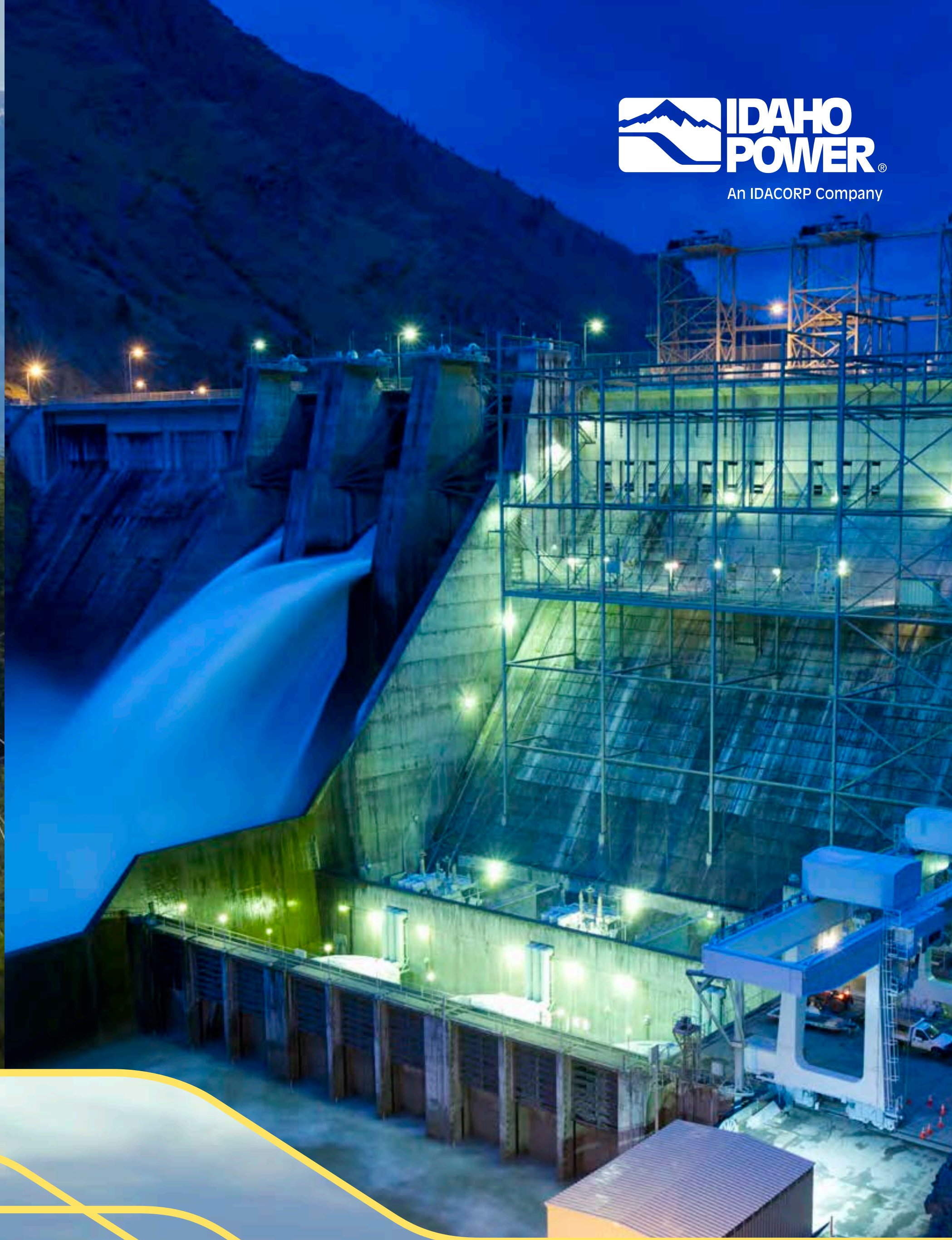

IDAHO POWER®
An IDACORP Company

2013 Integrated Resource Plan

APPENDIX A

Sales and Load Forecast

June 2013

2013

Integrated Resource Plan

APPENDIX A

Sales and Load Forecast

June 2013

An IDACORP Company

ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2013 Integrated Resource Plan. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the Integrated Resource Plan. The Idaho Power team is comprised of individuals that represent many different departments within the company. The Integrated Resource Plan team members are responsible for preparing forecasts, working with the Advisory Council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.

SAFE HARBOR STATEMENT

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

This page left blank intentionally.

INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as an appendix to its *2013 Integrated Resource Plan* (IRP). The sales and load forecast is Idaho Power's best estimate of the future demand for electricity within the company's service area. The forecast covers the 20-year period from 2013 through 2032.

The expected-case monthly average load forecast represents Idaho Power's estimate of the most probable outcome for load growth during the planning period and is based on the most recent economic forecast for Idaho Power's service area. However, the actual path of future electricity sales will not follow the exact path suggested by the expected-case load forecast. Therefore, four additional load forecasts were prepared, two that provide a range of possible load growths due to economic uncertainty and two that address the load variability associated with abnormal weather. The high- and low-growth scenarios provide a range of possible load growths over the planning period due to variable economic, demographic, and other non-weather-related influences. The high-growth and low-growth scenarios were prepared based on statistical analyses to empirically reflect uncertainty inherent in the load forecast. The 70th-percentile and 90th-percentile load forecast scenarios were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to more adverse weather conditions.

The expected-case load forecast assumes median temperatures and median rainfall. Because actual loads can vary significantly depending on weather conditions, two alternative scenarios were considered: a 70th-percentile average load forecast and 90th-percentile average load forecast. The 70th-percentile load forecast assumes monthly loads that can be exceeded in 3 out of 10 years (30% of the time). The 90th-percentile load forecast assumes monthly loads that can be exceeded in 1 out of 10 years (10% of the time).

In the expected-case scenario, Idaho Power's system load is forecast to increase to 2,154 average megawatts (aMW) in the year 2032 from the 2013 forecast load of 1,759 aMW. The expected-case forecast system load growth rate averages 1.1 percent per year over the 20-year planning period (2013–2032). In the more critical 70th-percentile load forecast used for resource planning, the system load is forecast to reach 2,201 aMW by 2032. The Idaho Power system peak load (95th percentile) is forecast to grow to 4,418 megawatts (MW) in the year 2032 from the actual system summer peak of 3,245 MW that occurred on Thursday, July 12, 2012, at 4:00 p.m. In the expected-case scenario, the Idaho Power system peak increases at an average growth rate of 1.4 percent per year over the 20-year planning period (2013–2032). The number of Idaho Power active retail customers is expected to increase from the December 2012 level of 500,000 customers to over 667,000 customers at year-end 2032.

This year's economic forecast was based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics June 2012 macroeconomic forecast strongly influenced *Appendix A—Sales and Load Forecast*. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an in-house economic forecast model and database. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics were also used in the development of *Appendix A—Sales and Load Forecast*.

Economic growth assumptions influence several classes of service growth rates. The number of households in Idaho is projected to grow at an annual average rate of 1.2 percent during the forecast period. The growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area households are derived from county-specific household forecasts. The number of households, incomes, employment projections, economic output, real retail electricity prices, and customer consumption patterns are used to develop load projections.

In addition to the economic assumptions used to drive the expected-case forecast scenario, several specific assumptions were incorporated into the forecasts of the individual sectors. Further discussion of the assumptions is presented in the sections of this report pertaining to the individual sectors.

The future load impacts of implemented and committed Idaho Power energy efficiency demand-side management (DSM) programs are considered within *Appendix A—Sales and Load Forecast*. These programs and their expected impacts are addressed in more detail in Idaho Power's *Demand-Side Management 2012 Annual Report*. This report is Appendix B to the 2013 IRP.

During the 20-year forecast horizon, there could be major changes in the electric utility industry, such as carbon regulations and subsequent higher electricity prices impacting future electricity demand. In addition, the price and volatility of substitute fuels, such as natural gas, may also impact future demand for electricity. The high degree of uncertainty associated with such changes is reflected in the economic high- and low-load growth scenarios previously described. The impact of carbon legislation on the load forecast is reflected in retail electricity prices, which are a driver in the major sector sales forecasting model. The alternative sales and load scenarios of *Appendix A—Sales and Load Forecast* were prepared under the assumption that Idaho Power will continue to serve all customers in its franchised service area during the planning period.

Data describing the historical and projected figures for the sales and load forecast is presented in Appendix A1 of this report.

2013 IRP Sales and Load Forecast

Average Load

The 2013 IRP average system load forecast is lower than the 2011 IRP average system load forecast in all years of the forecast period. The expected recovery reflected in the economic forecast used for the 2011 IRP was determined too optimistic in terms of a rapid recovery from the recession. The updated variables driving the 2013 forecast reflect this recent performance. The stalled recovery in the national and, to a lesser extent, service-area economy caused load growth to stall through 2011. However, in 2012, the recovery was evident, with strength exhibited in most all economic series to date. Longer-term, higher-retail electricity price assumptions that incorporate estimates of assumed carbon legislation serve to decrease the forecast of average loads, especially in the second 10 years of the forecast period.

Significant factors and considerations that influenced the outcome of the 2013 IRP load forecast include the following:

- The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed Hoku Materials will not come on-line, and the 74 aMW of energy originally anticipated are excluded from this sales and load forecast.

- The 2011 IRP sales and load forecast included a high-probability new customer referred to as "Special". At the time the forecast was prepared (August 2010), several interested parties had taken significant steps toward the development and location of their businesses within Idaho Power's service area. At that time, it was determined that the likelihood of the load materializing was sufficient to warrant its inclusion in the IRP. Ultimately, the contract was not completed and the load did not materialize as expected. For the 2013 IRP, Idaho Power has assumed this "Special" contract will not come on-line, and the 54 aMW of energy originally anticipated are excluded from this sales and load forecast.

- The load forecast used for the 2013 IRP reflects a near-term recovery in the service-area economy following a severe recession in 2008 and 2009 that kept sales from growing through 2011. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth of new households and, consequently, the number of residential customers being added to Idaho Power's service area. However, in 2011 and 2012, residential and commercial customer growth, along with housing and industrial activity, have shown signs of a meaningful and sustainable recovery. By 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004).

- The electricity price forecast used to prepare the sales and load forecast in the 2013 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2011 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2013 IRP price forecast yields higher future prices. The retail prices are mostly higher in the second 10 years of the planning period and impact the sales forecast negatively, a consequence of the inverse relationship between electricity prices and electricity demand.

- There continues to be significant uncertainty associated with the industrial and special-contract sales forecasts due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an unknown magnitude of the energy and peak-demand requirements. The current sales and load forecast reflects only those commercial or industrial customers that have made a sufficient and significant investment indicating a commitment of the highest probability of locating in the service area. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest but have not made sufficient commitments are not included in the current sales and load forecast.

- Conservation impacts, including DSM energy efficiency programs and codes and standards, are considered and integrated into the sales forecast. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning. The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C—Technical Appendix*.

- The 2013 irrigation sales forecast is slightly higher than the 2011 IRP forecast through 2015, likely due to recent high commodity prices and changing crop patterns. Farmers have taken advantage of the commodities market by planting greater acreage than in the recent past. After 2015, the sales forecast is slightly lower than the previous IRP forecast, primarily due to higher electricity prices. The continued conversion of irrigation systems from labor-intensive hand-lines to electrically operated pivot sprinklers continues to impact increased irrigation energy consumption.

Peak-Hour Demands

Peak-day temperatures and the growth in average loads drive the peak forecasting model regressions. The peak forecast results and comparisons with previous forecasts differ for a number of reasons that include the following:

- The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed Hoku Materials will not come on-line, and the 82 MW of peak demand originally anticipated are excluded from this sales and load forecast.

- As referenced previously, the 2011 IRP sales and load forecast included a new customer referred to as "Special" that failed to materialize. For the 2013 IRP, Idaho Power has assumed this "Special" contract will not come on-line, and the 60 MW of peak demand originally anticipated is excluded from this sales and load forecast.

- The 2013 IRP peak-demand forecast considers the impact of committed and implemented energy efficiency DSM programs on peak demand.

- The 2013 IRP peak-demand forecast model explicitly excludes the impact of demand response programs to establish peak impacts to effectively plan for demand response and supply-side resources in meeting peak demand. Demand response programs impacts are accounted for in the IRP load and resource balance as a reduction in peak demand.

- The peak model develops peak-scenario impacts based on historical probabilities of peak-day temperatures at the 50^{th}, 90^{th}, and 95^{th} percentiles of occurrence for each month of the year.

- Historical peak-demand data is considered in the peak-model regressions. Based on a historical comparison of percentiles, the July 2002, July 2003, June 2005, and July 2005 peak-day temperatures were near the 100^{th} percentile, and their addition to the regression models impacted forecast results. More recently, all-time system peaks were reached in July 2007, June 2008, and July 2012 and were incorporated into the peak forecast model regressions.

- Idaho Power continues to use a median peak-day temperature driver in lieu of an average peak-day temperature driver. The median peak-day temperature has a 50-percent probability of being exceeded. Peak-day temperatures are not normally distributed and can be skewed by one or more extreme observations as referred to in the previous bulleted item; therefore, the median temperature better reflects expected temperatures within the context of probabilistic percentiles. The weighted average peak-day temperature drivers are calculated over the 1982 to 2011 time period (the most recent 30 years).

This page left blank intentionally.

OVERVIEW OF THE FORECAST

The sales and load forecast is constructed by developing a separate forecast for each sales category. Independent sales forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak-demand forecasts are developed for special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); the Idaho National Laboratory (INL); and Hoku Materials. These four special-contract customers are combined into a single forecast category labeled additional firm load. Last, the contract off-system category represents long-term contracts to supply firm energy and demand to off-system customers. At this time, there are no long-term contracts. The assumptions for each of the individual categories are described in greater detail in the respective sections.

Since the residential, commercial, irrigation, and industrial sales forecasts provide a forecast of sales as billed, it is necessary to adjust these billed sales to the proper time frame to reflect the required generation needed in each calendar month. To determine calendar-month sales from billed sales, the billed sales must first be allocated to the calendar months in which they are generated. The calendar-month sales are then converted to calendar-month load by adding losses and dividing by the number of hours in each month.

Loss factors are determined by Idaho Power's Distribution Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses.

The peak-load forecast was prepared in conjunction with the 2013 sales forecast. Idaho Power has two distinct peak periods: 1) a winter peak, resulting from space-heating demand that normally occurs in December, January, or February; and 2) a larger summer peak that normally occurs in late June or July. The summer peak generally occurs when extensive air conditioning (A/C) use coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of average peak-day temperatures, the historical monthly average load, and precipitation (summer only). The peak forecast uses statistically derived peak-day temperatures based on the most recent 30 years of climate data for each month. Peak loads for the INL, Micron Technology, and Simplot Fertilizer are forecast based on a historical analysis and contractual considerations.

The primary external factors in the forecast are macroeconomic and demographic data. Moody's Analytics provides the macroeconomic forecasts. The national, state, MSA, and county economic and demographic projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data.

Fuel Prices

Fuel prices, in combination with service-area economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future demand for electricity. The sales and load forecast is also influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move higher throughout the forecast period, reducing future electricity sales. Class level and economic-sector-level regression models were used to identify the relationships between real historical electricity prices and historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. The United States (US) Energy Information Administration (EIA) provides the forecasts of long-term changes in nominal natural gas prices. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 1. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel-price growth rates in the commercial, industrial, and irrigation sectors.

Table 1. Residential fuel-price escalation (2013–2032) (average annual percent change)

	Nominal	Real*
Electricity—2013 IRP	3.2%	1.3%
Electricity—2011 IRP	1.5%	(0.1%)
Natural Gas	3.2%	1.3%

* Adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1972 to 2012 and over the forecast period 2013 to 2032. Both nominal and real prices are shown. In the 2013 IRP, nominal electricity prices are expected to climb to nearly 17 cents per kilowatt-hour (kWh) by the end of the forecast period in 2032. Real electricity prices (inflation adjusted) are expected to increase over the forecast period at an average rate of 1.3 percent annually. In the 2011 IRP, nominal electricity prices were assumed to slowly climb to nearly 13 cents per kWh by 2032, and real electricity prices (inflation adjusted) were expected to remain flat over the forecast period at an average rate of -0.1 percent annually. The impact of the higher real electricity price forecast on the 2013 IRP load forecast serves to slow the growth in electricity sales, especially in the last 10 years of the forecast period.

The electricity price forecast used to prepare the sales and load forecast in the 2013 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2011 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2013 IRP price forecast yielded higher future prices. The retail prices are mostly higher in the second 10 years of the planning period and impact the sales forecast negatively, a consequence of the inverse relationship between electricity prices and electricity demand.

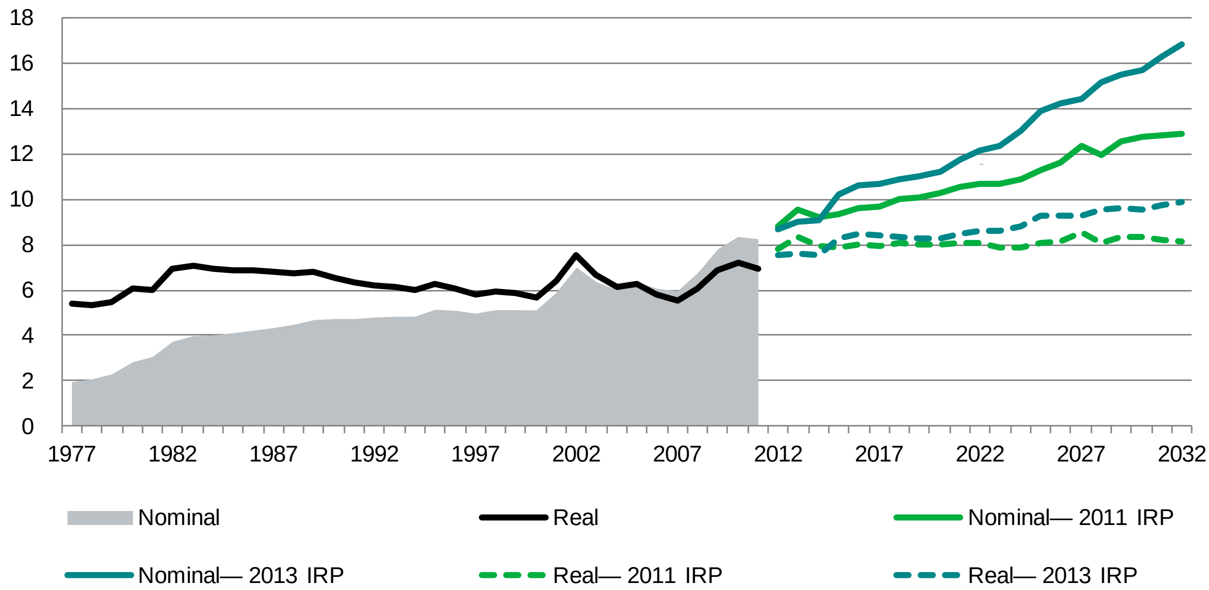

Figure 1. Forecast residential electricity prices (cents per kWh)

Electricity prices for Idaho Power customers increased significantly in 2001 and 2002 because of the power cost adjustment (PCA) impact on rates, a direct result of the western US energy crisis of 2000 and 2001. Prior to 2001, Idaho Power's electricity prices were historically quite stable. From 1990 to 2000, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent annually.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1970 to 2011 and forecast prices from 2012 to 2032. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since spiking in 2001, natural gas prices moved downward for a couple of years before moving sharply upward in 2004 through 2006. The collapse in natural gas prices that began in 2009 led to much lower prices in 2010 and 2011. Nominal natural gas prices are expected to rise slowly through 2014, then more rapidly throughout the remainder of the forecast period until nearly doubling at an average rate of 3.2 percent per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 1.3 percent annually.

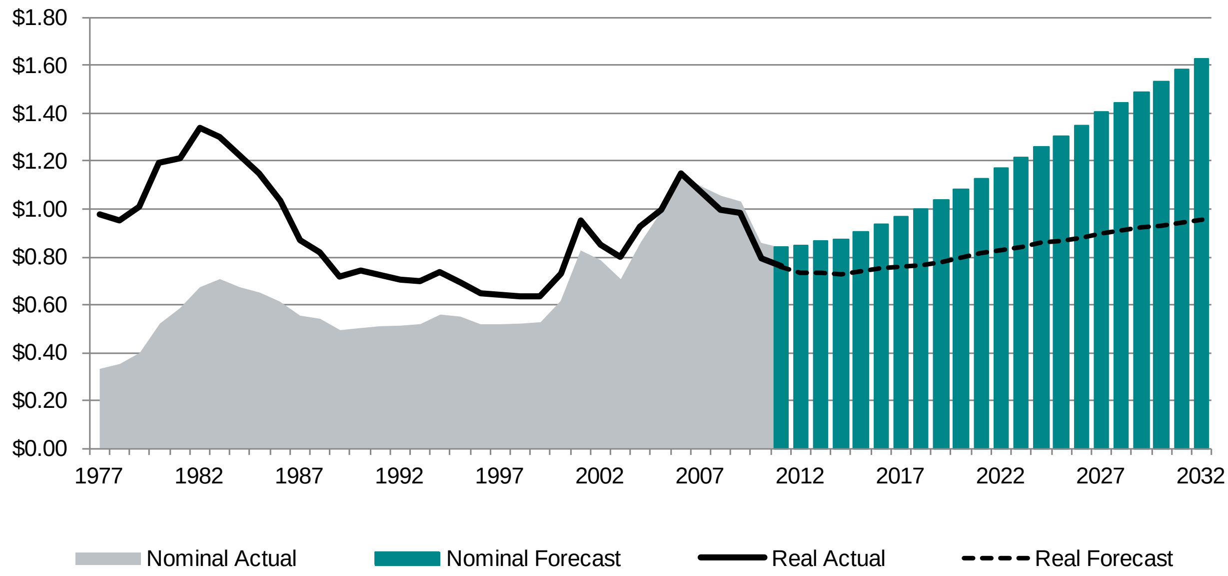

Figure 2. Forecast residential natural gas prices (dollars per therm)

If future natural gas price increases outpace electricity price increases, the operating costs of space heating and water heating with electricity would become more advantageous when compared to that of natural gas. However, in the 2013 IRP price forecast, the long-term growth rates of electricity and natural gas prices are nearly identical.

Electric Vehicles

The load forecast includes an update of the impact of plug-in electric vehicles on the system load. The 2011 IRP forecast model relied heavily on the forecast methodologies of the Electric Power Research Institute (EPRI) and Oak Ridge National Laboratory. At the time, these models did not have actual consumer adoption data or most recent domestic fuel supply impacts of advanced technologies in crude oil production. The 2013 IRP electric-vehicle forecast update integrates service area vehicle registration data with updated technological and economic variables impacting adoption, as well as vehicle charging behavior. This update also integrates the fuel and technology forecasts of the Department of Energy's (DOE) National Energy Model (NEM).

The Idaho Power vehicle share forecast is based on a Bass diffusion model of adoption as informed by actual vehicle registration. Load impacts from adoption are derived from assumptions of battery-only and hybrid plug-in shares evident from historical registration data and informed by NEM forecasts. The combined vehicle forecast represents just over 4 percent of new vehicle sales in the service area at the end of the planning period. Battery-only vehicles represent 15 percent of the total, and the updated forecast model reflects a much slower adoption rate than anticipated in the 2011 forecast. The all-electric share is consistent with the DOE Annual Energy Outlook (AEO) 2013 update that forecasts all-electric vehicles at less than 1 percent of sales in 2040.

The resulting impact on the load forecast is about 1 aMW in 2020, reaching approximately 4 aMW at the end of the forecast period in 2032. The load impacts were allocated to the residential and commercial sales forecasts using an 80/20 split, respectively.

Idaho Power continues to capture consumer behavioral data and other salient market information associated with electric-vehicle adoption to improve the forecasting model in future forecasts.

Forecast Probabilities

Load Forecasts Based on Weather Variability

The future demand for electricity by customers in Idaho Power's service area is represented by three load forecasts reflecting a range of load uncertainty due to weather. The expected-case load forecast represents the most probable projection of system load growth during the planning period and is based on the most recent national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power's service area.

The expected-case load forecast assumes median temperatures and median precipitation (i.e., there is a 50-percent chance loads will be higher or lower than the expected-case loads due to colder-than-median or hotter-than-median temperatures or wetter-than-median or drier-than-median precipitation). Since actual loads can vary significantly depending on weather conditions, two alternative scenarios were considered that address load variability due to weather.

Maximum load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum load occurs when the lowest recorded levels of HDD are assumed in winter and the lowest recorded levels of CDD and GDD, combined with the highest level of precipitation, are assumed in summer.

For example, at the Boise Weather Service office, the median HDD in December from 1982 to 2011 (the most recent 30 years) was 1,039. The 70th-percentile HDD is 1,074 and would be exceeded in 3 out of 10 years. The 90th-percentile HDD is 1,291 and would be exceeded in 1 out of 10 years. The 100th-percentile HDD (the coldest December over the 30 years) is 1,619 and occurred in December 1985. This same concept was applied in each month throughout the year in only the weather-sensitive customer classes: residential, commercial, and irrigation.

In the 70th-percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70th percentile of HDD in wintertime and at the 70th percentile of CDD in summertime. In the 70th-percentile irrigation load forecast, GDD were assumed to be at the 70th percentile and precipitation at the 30th percentile, reflecting drier-than-median weather. The 90th-percentile load forecast was similarly constructed.

Idaho Power loads are highly dependent on weather, and these two scenarios allow the careful examination of load variability and how it may impact future resource requirements. It is important to understand that the probabilities associated with these forecasts apply to any given month. To assume temperatures and precipitation would maintain a 70th-percentile or 90th-percentile level continuously, month after month throughout an entire year, would be much less probable. Monthly forecast numbers are evaluated for resource planning, and caution should be used in interpreting the meaning of the annual average load figures being reported and graphed for the 70th-percentile or 90th-percentile forecasts.

Table 2 summarizes the load scenarios prepared for the 2013 IRP. Three average load scenarios were prepared based on a statistical analysis of the historical monthly weather variables listed. The probability associated with each average load scenario is also indicated in the table. In addition, three peak-demand scenarios were prepared based on a statistical analysis of historical peak-day average temperatures, and the probability associated with each peak-demand scenario is also indicated in Table 2.

Table 2. Average load and peak-demand forecast scenarios

Scenario	Weather Probability	Probability of Exceeding	Weather Driver
Forecasts of Average Load			
90th Percentile	90%	1-in-10 years	HDD, CDD, GDD, precipitation
70th Percentile	70%	3-in-10 years	HDD, CDD, GDD, precipitation
Expected Case	50%	1-in-2 years	HDD, CDD, GDD, precipitation
Forecasts of Peak Demand			
95th Percentile	95%	1-in-20 years	Peak-day temperatures
90th Percentile	90%	1-in-10 years	Peak-day temperatures
50th Percentile	50%	1-in-2 years	Peak-day temperatures

The analysis of resource requirements is based on the 70th-percentile average load forecast coupled with the 95th-percentile peak-demand forecast to provide a more adverse representation of the average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50th percentile) average-load forecast and the 90th-percentile peak-demand forecast are typically used.

Load Forecasts Based on Economic Uncertainty

The expected-case load forecast is based on the most recent economic forecast for Idaho Power's service area and represents Idaho Power's most probable outcome for load growth during the planning period. The expected-case load forecast reflects the integration of existing energy efficiency DSM program effects as a reduction to the average load forecast. In addition, retail electricity prices also impact the growth in electricity sales long term.

Two additional load forecasts for the Idaho Power service area were prepared. The forecasts provide a range of possible load growths for the 2013 to 2032 planning period due to high and low economic and demographic conditions. The high- and low-economic-growth scenarios were prepared based on a statistical analysis to empirically reflect the uncertainty inherent in the load forecast. The average growth rates for the high- and low-growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1987–2011).

The estimated probabilities for the three load scenarios are reported in Table 2. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario. The probability estimates assume the expected forecast is the median growth path (i.e., there is a 50-percent probability the actual growth rate will be less than the expected-case growth rate and a 50-percent chance the actual growth rate will be greater than the expected-case growth rate). In addition, the probability estimates assume the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1987–2011). The high- and low-case load forecasts also reflect the integration of existing energy efficiency DSM program effects as a reduction to the average load wintertime forecasts.

Two types of probability estimates are reported in Table 3. The first probability, the probability of exceeding, shows the likelihood that the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10-percent probability the actual growth rate will exceed the growth rate projected in the high scenario; conversely, there is a 10-percent chance the actual growth rate will fall below that of the low scenario. In other words, over a 20-year period, there is an 80-percent probability that the actual growth rate of system load will fall between the growth rates projected in the high and low scenarios. The second probability estimate, the probability of occurrence, indicates the likelihood that the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26-percent probability the actual growth rate will be closer to the high scenario than to any of the other forecast scenarios for the entire 20-year planning horizon. Probabilities for shorter, 1-year, 5-year, and 10-year time periods are also shown in Table 3.

Table 3. Forecast probabilities

Probability of Exceeding				
Scenario	**1-year**	**5-year**	**10-year**	**20-year**
Low Growth	90%	90%	90%	90%
Expected Case	50%	50%	50%	50%
High Growth	10%	10%	10%	10%
Probability of Occurrence				
Scenario	**1-year**	**5-year**	**10-year**	**20-year**
Low Growth	26%	26%	26%	26%
Expected Case	48%	48%	48%	48%
High Growth	26%	26%	26%	26%

The system load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and on-system contracts (including past sales to Raft River and the City of Weiser).

Idaho Power system load projections are reported in Table 4 and pictured in Figure 3. The expected-case system load-forecast growth rate averages 1.1 percent per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 0.6 percent per year throughout the forecast period. The high scenario projects load growth of 1.5 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These scenario forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

Table 4. System load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
Low	1,738	1,760	1,826	1,949	0.6%
Expected	1,759	1,842	1,956	2,154	1.1%
High	1,829	1,972	2,145	2,447	1.5%

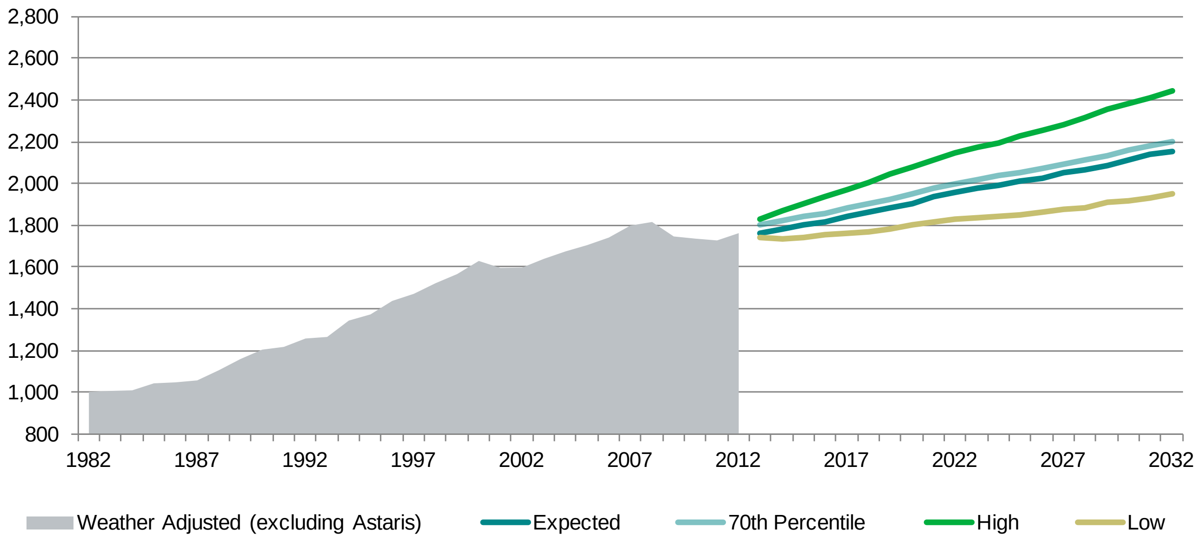

Figure 3. Forecast system load (aMW)

RESIDENTIAL

The expected-case residential load is forecast to increase from 574 aMW in 2013 to 704 aMW in 2032, an average annual compound growth rate of 1.1 percent. In the 70th-percentile scenario, the residential load is forecast to increase from 590 aMW in 2013 to 724 aMW in 2032, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 5 and shown graphically in Figure 4.

Table 5. Residential load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
90th Percentile	623	649	687	763	1.1%
70th Percentile	590	614	650	724	1.1%
Expected Case	574	597	632	704	1.1%

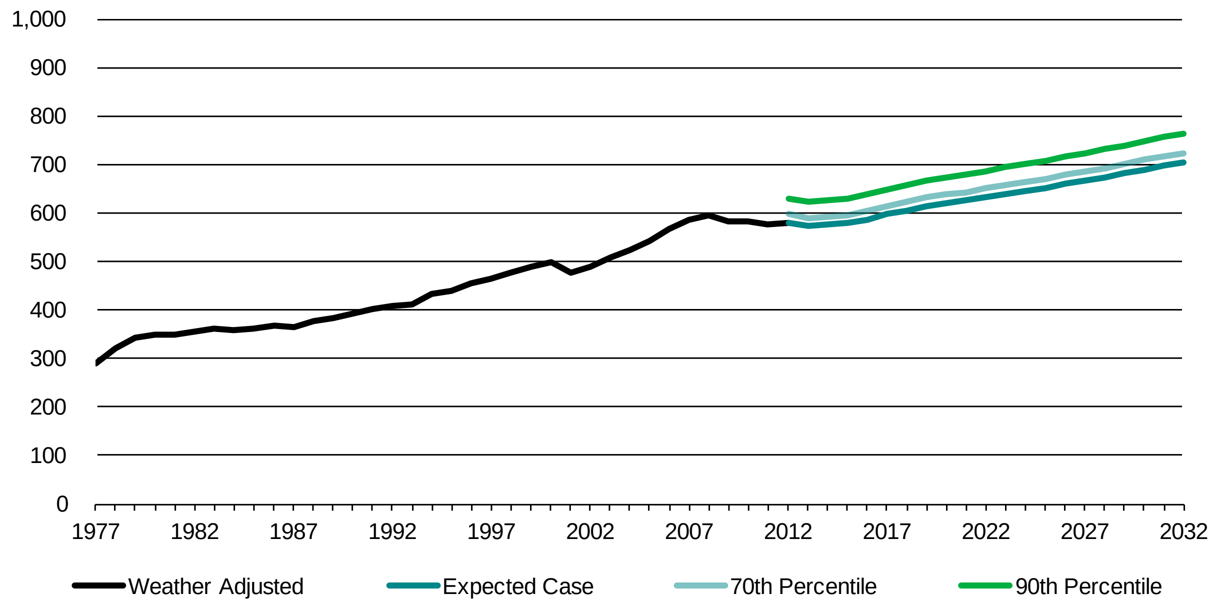

Figure 4. Forecast residential load (aMW)

Sales to residential customers made up 33 percent of Idaho Power's system sales in 1982 and 36 percent of system sales in 2012. The residential customer proportion of system sales is forecast to be approximately 36 percent in 2032. There were 416,000 residential customers as of December 2012. The number of residential customers is projected to increase to approximately 554,000 by December 2032. The relative customer proportions of Idaho Power's system electricity sales are shown in Figure 15.

The average sales per residential customer were 13,700 kWh in 1977. Average sales increased to over 14,800 kWh per residential customer in 1979 before declining to 13,200 kWh in 2001. In 2002 and 2003, residential use per customer dropped dramatically—over 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices combined with a weak national and service-area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential use per customer to stabilize and rise through 2007. However, the recession in 2008 and 2009, combined with conservation programs designed to reduce electricity use served to slow the growth in residential use per customer. The average sales per residential customer are expected to slowly decline to approximately 11,200 kWh per year in 2032. Average annual sales per residential customer are shown in Figure 5.

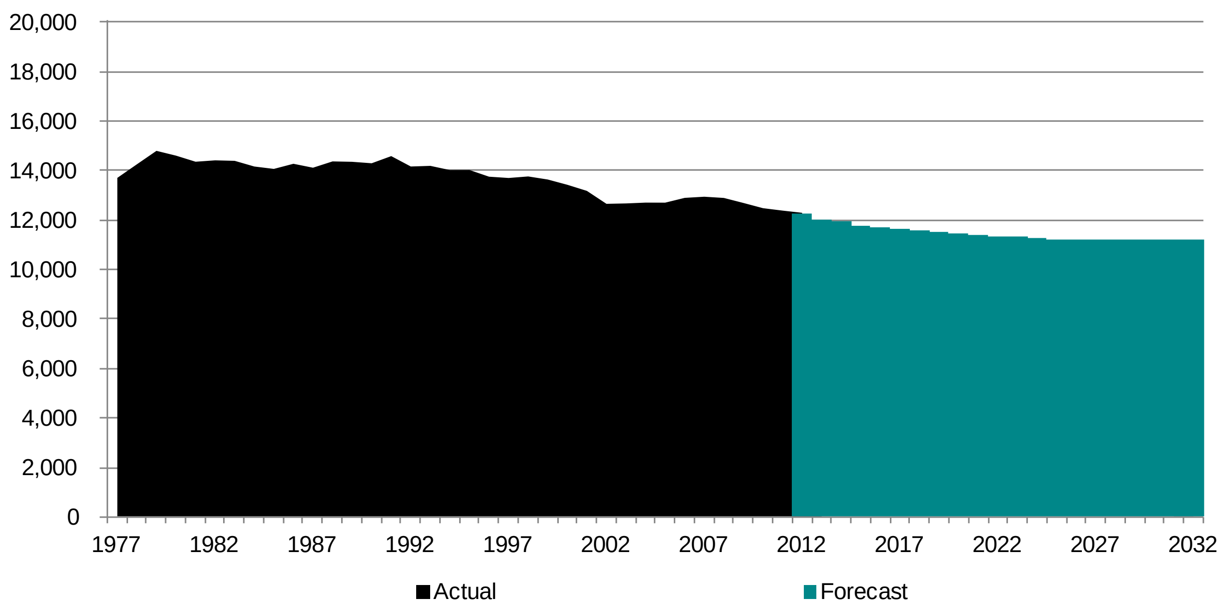

Figure 5. Forecast residential use per customer (weather-adjusted kWh)

The residential-use-per-customer forecast is based on a forecast of the number of residential customers and an econometric analysis of residential-sector sales. The number of residential customers being added each year is a direct function of the number of new service-area households as derived from Moody's Analytics June 2012 forecast of county housing stock and demographic data. The residential-customer forecast for 2013 to 2032 shows an average annual growth rate of 1.5 percent.

The residential sales forecast equation considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime), CDD (summertime), the number of service-area households as derived from Moody's Analytics forecasts of county housing stock, the real price of electricity, and the real price of natural gas. The forecast of residential use per customer is arrived at by dividing the residential sales forecast, which considers the impact of forecast DSM, by the residential-customer forecast.

Commercial

The commercial category is primarily made up of Idaho Power's small general-service and large general-service customers. Other schedules considered part of the commercial category are unmetered general-service, street-lighting service, traffic-control signal-lighting service, and dusk-to-dawn customer lighting.

In the expected-case scenario, the commercial load is projected to increase from 446 aMW in 2013 to 549 aMW in 2032. The average annual compound-growth rate of the commercial load is 1.1 percent during the forecast period. As referred to previously, the forecast does not include an assumption for growth from new customers that deviate from historical business failure and startup parameters. As summarized in Table 6, the commercial load in the 70th-percentile scenario is projected to increase from 451 aMW in 2013 to 556 aMW in 2032. The commercial load forecasts are illustrated in Figure 6.

Table 6. Commercial load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
90th Percentile	463	485	510	572	1.1%
70th Percentile	451	472	496	556	1.1%
Expected Case	446	466	490	549	1.1%

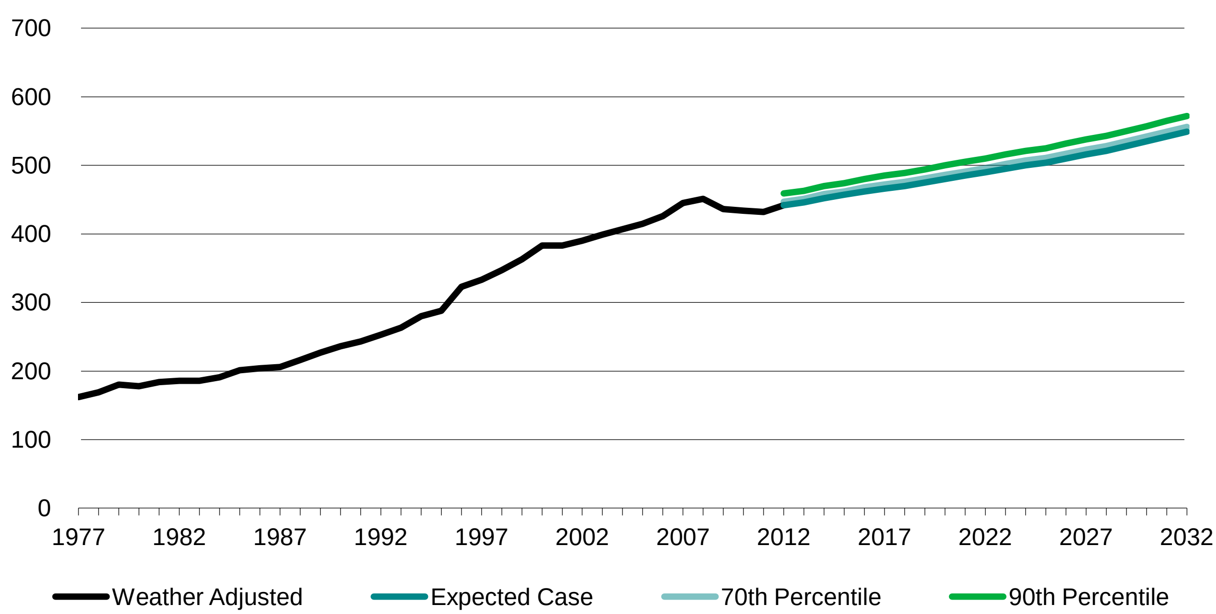

Figure 6. Forecast commercial load (aMW)

As of December 2012, Idaho Power had 66,000 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 1.6 percent, reaching 90,200 customers by 2032. Commercial customers consumed nearly 17 percent of Idaho Power system sales in 1982 and nearly 28 percent of system sales in 2012.

The commercial customer proportion of system sales is projected to remain at 28 percent of system sales by 2032. The relative customer proportions of Idaho Power's system electricity sales are shown in Figure 15.

The average consumption per commercial customer increased to a record 67,300 kWh in 2001. However, two years of significantly higher electricity prices combined with a weak national and service-area economy caused a setback in the growth of commercial use per customer beginning in 2002. The reduction in electricity prices in June 2003 and a recovery in the service-area economy slowed the rate of decline in commercial use per customer through 2007. However, a severe recession in 2008 and 2009 caused commercial use per customer to drop considerably. After flattening out from 2010 to 2012, commercial use per customer is projected to rise slowly through 2014 as the economy recovers, then continue its downward trend. The primary reasons for the long-term decline are higher retail electricity prices due to generating plant additions and DSM program impacts on energy sales. The average consumption per commercial customer is expected to decrease to approximately 53,500 kWh in 2032. The forecast average annual use per commercial customer is shown in Figure 7.

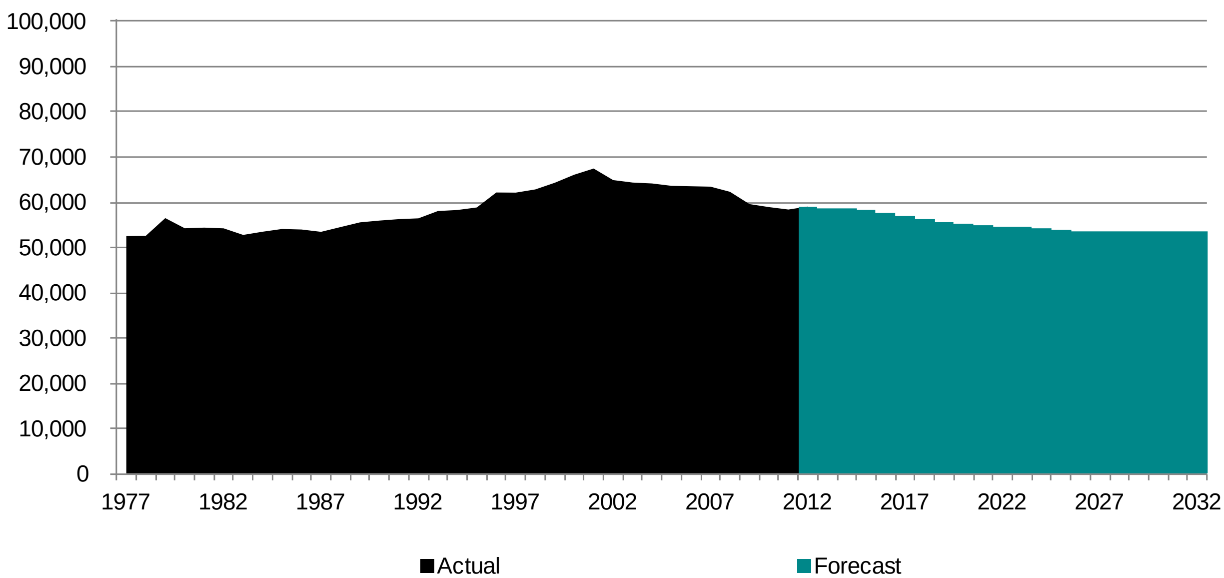

Figure 7. Forecast commercial use per customer (weather-adjusted kWh)

The commercial-use-per-customer forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial-sector sales. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. Additionally, the number of residential customers being added is a direct function of the number of new service-area households as derived from Moody's Analytics June 2012 economic forecast of county housing stock and demographic data. The commercial-customer forecast for 2013 to 2032 shows an average annual growth rate of 1.6 percent.

The commercial-sales forecast equation considers several factors affecting electricity sales to the commercial sector. Commercial sales are a function of HDD (wintertime); CDD (summertime); the number of service-area households and service-area employment as derived from

Moody's Analytics forecasts; and the real price of electricity. The commercial-use-per-customer forecast is arrived at by dividing the commercial sales forecast, which considers the impacts of forecast DSM, by the commercial-customer forecast.

This page left blank intentionally.

IRRIGATION

The irrigation category is made up of agricultural irrigation service customers. Service under this schedule is applicable to power and energy supplied to agricultural-use customers at one point-of-delivery for operating water pumping or water-delivery systems to irrigate agricultural crops or pasturage.

Throughout the forecast period, the expected-case irrigation load is forecast to remain flat at 200 aMW from 2013 to 2032, an average annual compound growth rate of 0 percent. The expected-case, 70th-percentile, and 90th-percentile scenarios forecast no growth in irrigation load from 2013 to 2032. In the 70th-percentile scenario, irrigation load is projected to be 215 aMW in 2013 and 215 aMW in 2032. The individual irrigation load forecasts are reported in Table 7 and Figure 8, which illustrates the poorer economic conditions and dramatic reduction in land put into production in the mid-1980s.

Table 7. Irrigation load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
90th Percentile	235	235	236	235	0.0%
70th Percentile	215	215	216	215	0.0%
Expected Case	200	200	202	200	0.0%

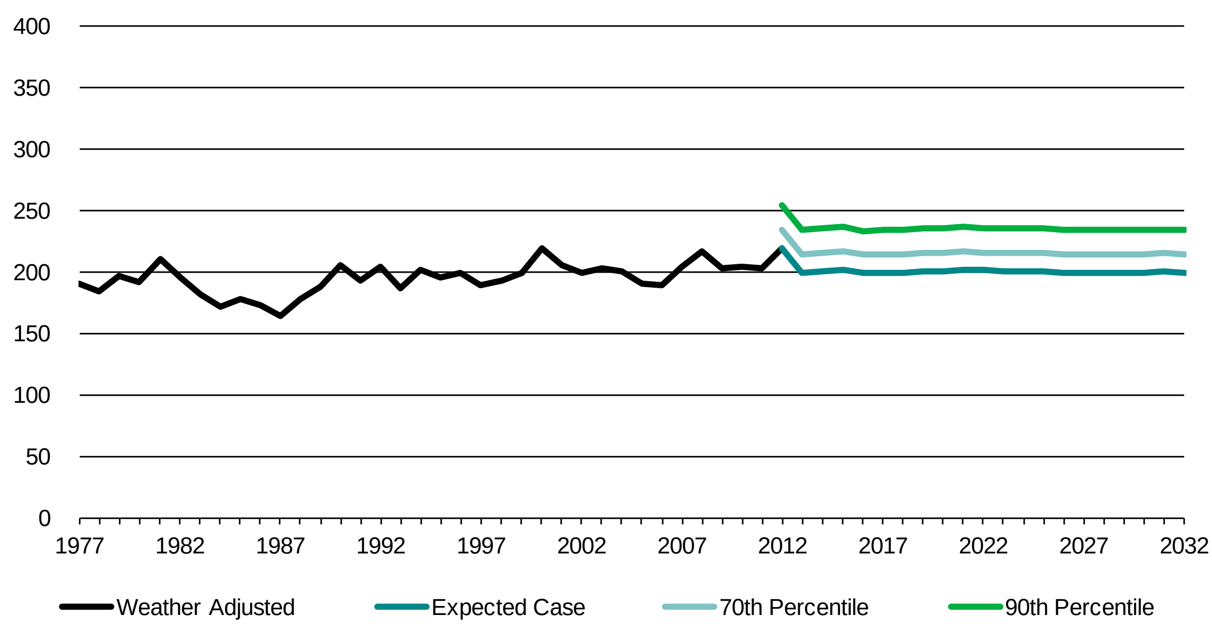

Figure 8. Forecast irrigation load (aMW)

It is important to understand that the annual average loads in Table 7 and Figure 8 are calculated using the 8,760 hours in a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can exceed 800 MW. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy consumed during the hour of the annual system peak and 30 percent of the energy consumed during July for general business sales. The monthly forecast load figures are being evaluated for resource planning purposes, not the annual average loads.

The 2013 irrigation sales forecast is slightly higher than the 2011 IRP forecast through 2015, likely due to recent high commodity prices and changing crop planting patterns. Farmers have taken advantage of the commodities market by planting increasing levels of acreage. After 2015, the sales forecast is slightly lower than the previous IRP forecast, primarily due to higher electricity prices influencing demand. The conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs, explains most of the increased energy consumption in recent years.

The 2013 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; spring rainfall; *Moody's Gross Product: Agriculture, for Idaho*; *Moody's Producer Price Index: Prices Received by Farmers, All Farm Products*; and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to the voluntary load-reduction program.

In early 2001, wholesale electricity prices reached unprecedented levels; Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load-reduction program that paid irrigators to reduce their electricity consumption in 2001. The voluntary load-reduction program was effective and resulted in a 30-percent, or approximately 500,000-megawatt-hour (MWh), reduction in 2001 irrigation sales. The 2001 irrigation sales and corresponding loads have been adjusted upward by 499,319 MWh to reflect a more normal 2001 irrigation season.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 1,990,000 MWh in 2000. Idaho Power projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

Irrigation sales represented about 18 percent of weather-normalized Idaho Power system sales in 1982 and reached a maximum proportion of 20 percent of Idaho Power system sales in 1977. In 2012, the irrigation proportion of system sales was 14 percent due to the much higher relative growth in other customer classes. By 2032, irrigation customers are projected to consume less than 10 percent of Idaho Power system sales. The irrigation customer load proportion is shown in Figure 15.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2012, the number of active irrigation accounts had increased to 18,675 and is projected to be nearly 23,000 at the end of the planning period in 2032.

Since 1988, Idaho Power has experienced some growth in the number of irrigation customers, but very little, if any, growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low, and the kWh use per customer is substantially lower than the average existing Idaho Power irrigation customer. This is because water for furrow irrigation is gravity-drawn from canals and not pumped from deep, groundwater wells.

Bell Rapids, a large, high-lift cooperative irrigation company that irrigated about 25,000 acres from 1970 to 2004, was Idaho Power's largest irrigation customer. The Bell Rapids combined accounts included more than 40 irrigation service points that accounted for approximately 3 to 4 percent of Idaho Power's annual irrigation sales. In early 2005, the State of Idaho purchased the water rights from Bell Rapids, which resulted in the loss of Bell Rapids as an irrigation customer. Prior to 2005, Bell Rapids consumed, on average, 55,000 MWh annually.

In the future, factors related to the conjunctive management of ground and surface water and the possible litigation associated with the resolution will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

This page left blank intentionally.

INDUSTRIAL

The industrial category is made up of Idaho Power's large power service (Schedule 19) customers with monthly metered demands between 1,000 kilowatts (kW) and 20,000 kW. In 1975, Idaho Power had about 70 industrial customers, which represented about 10 percent of Idaho Power's system sales. By December 2012, the number of industrial customers had risen to 116, representing approximately 16 percent of system sales. Special contracts are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 267 aMW in 2013 to 367 aMW in 2032, an average annual growth rate of 1.7 percent (Table 8). As a general rule, industrial loads are not weather sensitive, and the forecasts in the 70th and 90th-percentile scenarios are identical to the expected-case industrial-load scenario. The industrial load forecast is pictured in Figure 9.

Table 8. Industrial load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
Expected Case..	267	294	319	367	1.7%

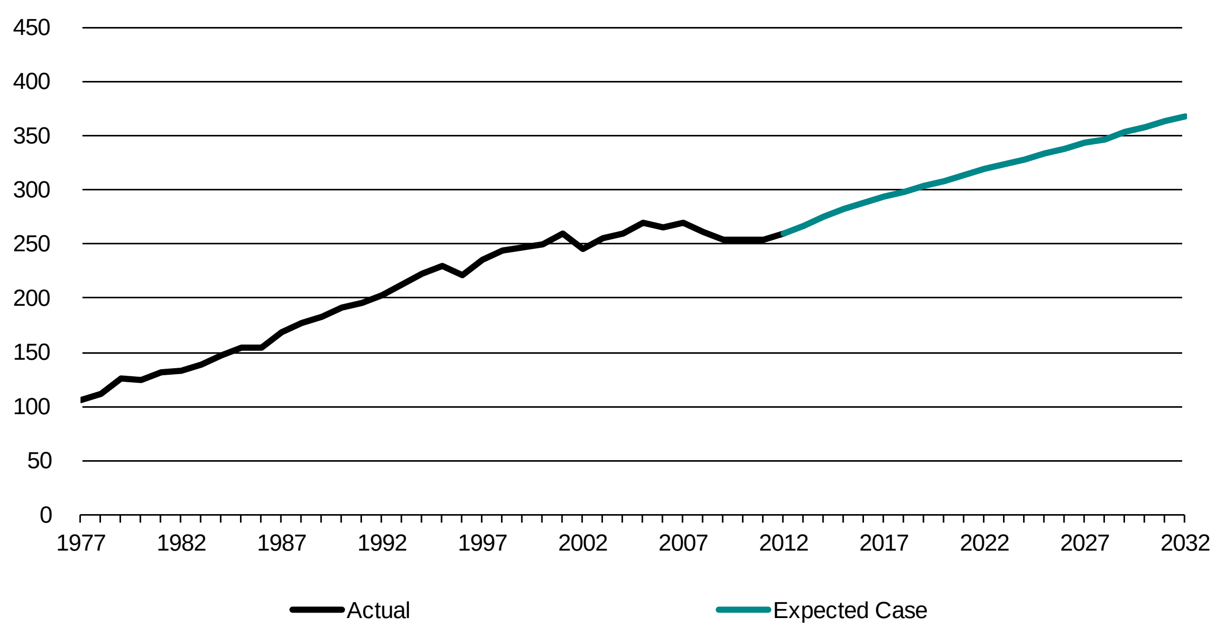

Figure 9. Forecast industrial load (aMW)

The industrial energy forecast is based on the most recent (June 2012) national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power's service area.

Since rate tariff definitions do not correspond with economic activity types, Idaho Power's Schedule 19 customers were categorized, and their historical electricity sales were summarized by economic activity. This is also true for the large commercial loads, so Schedule 9 primary and transmission customers' energy sales were also included for forecasting purposes and later recombined with the commercial-sector sales forecast. The appropriate employment series (or population time series) were matched to each economic sector or industry group. Regression models were developed for 16 industry groups to determine the relationship between historical electricity sales and historical employment, population, and/or other relevant explanatory variables. The estimated coefficients from the industry group regression models were then applied to the appropriate employment, population, and other relevant drivers, which resulted in the escalation of electricity sales to the various industry groups over time.

Figure 10 illustrates the 2012 industrial electricity consumption by industry group. By far, the largest share of electricity was consumed by the food manufacturing sector (47%); followed by other industry groups (17%); health care (7%); and computer and electronic product manufacturing, education, and other manufacturing (each representing 6%). As Figure 10 shows, several other industry groups make up the remaining share of the 2012 industrial electricity consumption.

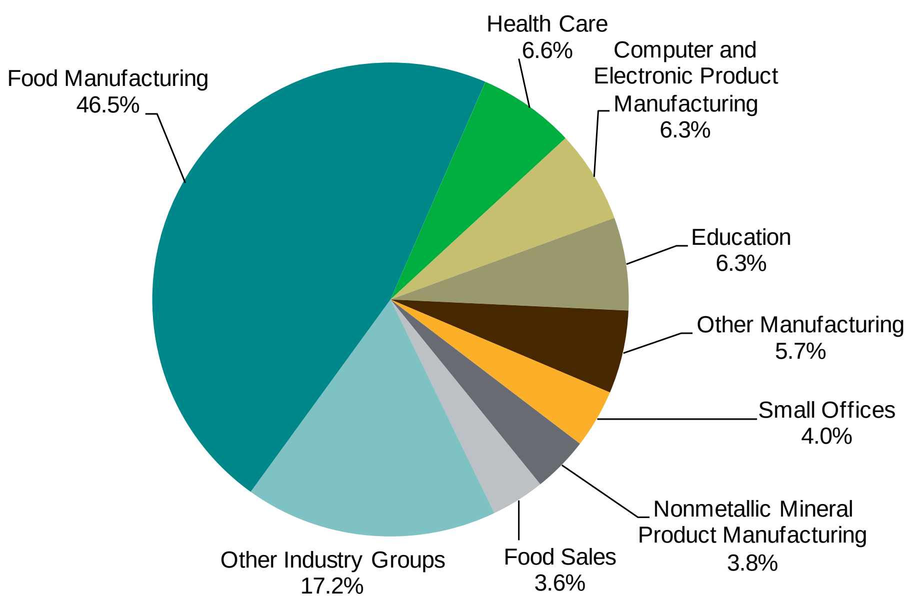

Figure 10. Industrial electricity consumption by industry group (based on 2012 figures)

ADDITIONAL FIRM LOAD

The additional firm load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each large-power customer. The contract and tariff schedule are approved by the appropriate commission. A special contract allows customer-specific, cost-of-service analysis and unique operating characteristics to be accounted for in the agreement.

A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special-contract customers recognized as firm-load customers. These special-contract customers are Micron Technology, Simplot Fertilizer, the INL, and Hoku Materials. The contract with Raft River expired on September 30, 2011.

In the expected-case forecast, additional firm load is expected to increase from 115 aMW in 2013 to 143 aMW in 2032, an average growth rate of 1.1 percent per year over the planning period (Table 9). The additional firm load energy and demand forecasts in the 70th and 90th-percentile scenarios are identical to the expected-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 11.

Table 9. Additional firm load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
Expected Case	115	121	140	143	1.1%

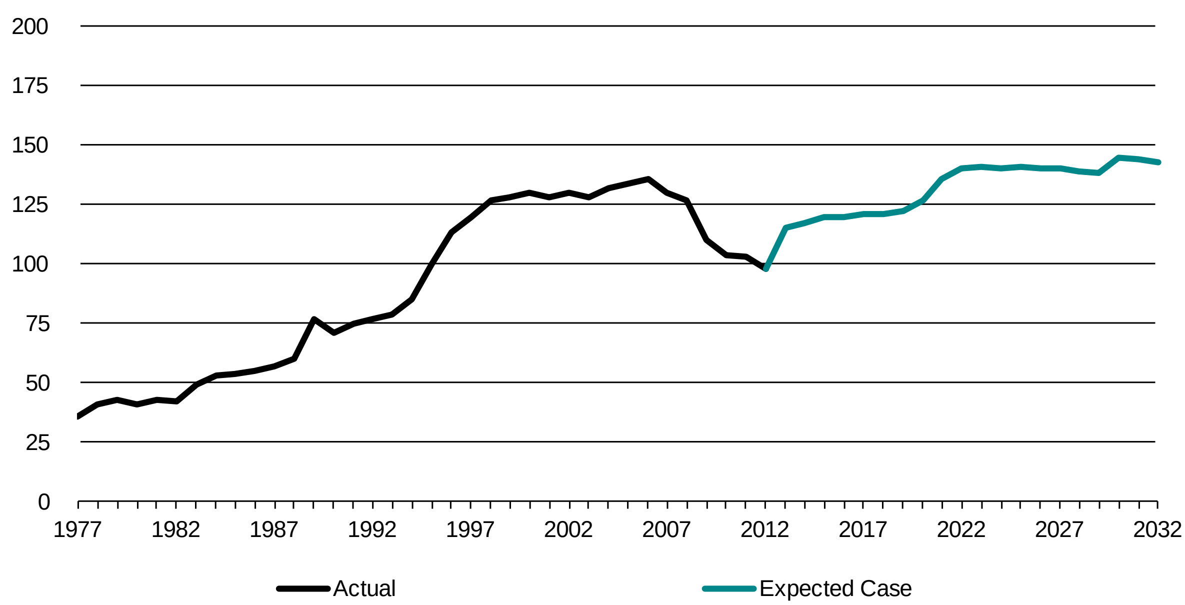

Figure 11. Forecast additional firm load (aMW)

Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Micron Technology's electricity use is expected to increase based on the market demand for their products.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western US. The future electricity usage at the plant is expected to grow slowly in 2013 and 2014, then stay flat throughout the remainder of the planning. The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics forecast of gross product in the pesticide, fertilizer, and other agricultural chemical manufacturing segment for the Pocatello MSA.

Idaho National Laboratory

The DOE provided an energy-consumption and peak-demand forecast through 2032 for the INL. The forecast calls for loads to slowly rise through 2015, remain flat for five years, rise dramatically through 2022, and stay at the higher level throughout the remainder of the forecast period.

Hoku Materials

The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed that Hoku Materials will not come on-line, and the 74 aMW of energy and 82 MW of peak demand originally anticipated are excluded from this sales and load forecast.

"Special" Contract

In the 2011 IRP sales and load forecast, there was an additional customer referred to as "Special" included with the additional firm load category (special contracts) even though no long-term contract had been fully executed. When that forecast was prepared (August 2010), several interested parties had taken significant steps toward the development and location of their businesses within Idaho Power's service area. It was determined at that time there was a real possibility of the new large load materializing. However, since the 2011 IRP, the likelihood of the new large load diminished. For the 2013 IRP, Idaho Power has assumed this "Special" contract will not come on-line, and the 54 aMW of energy and 60 MW of peak demand originally anticipated are excluded from this sales and load forecast.

Company System Peak

System peak load includes the sum of individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (including Astaris, historically) and on-system contracts (Raft River and the City of Weiser, historically).

The all-time system summer peak demand was 3,245 MW, recorded on Thursday, July 12, 2012, at 4:00 p.m. The previous summer peak demand was 3,214 MW and occurred on Monday, June 30, 2008, at 3:00 p.m. The summer system peak load growth accelerated from 1998 to 2008 as a record number of residential and commercial customers were added to the system and A/C became standard in nearly all new residential homes and new commercial buildings.

In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,344 MW in 2013 to 4,365 MW in the year 2032, an average growth rate of 1.4 percent per year over the planning period (Table 10). In the 95th-percentile forecast, the system summer peak load is expected to increase from 3,382 MW in 2013 to 4,418 MW in 2032. The three scenarios of projected system summer peak load are illustrated in Figure 12. The 2001 summer peak was dampened by the nearly 30-percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

Table 10. System summer peak load growth (MW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
95th Percentile	3,382	3,596	3,881	4,418	1.4%
90th Percentile	3,344	3,555	3,835	4,365	1.4%
50th Percentile	3,189	3,387	3,651	4,147	1.4%

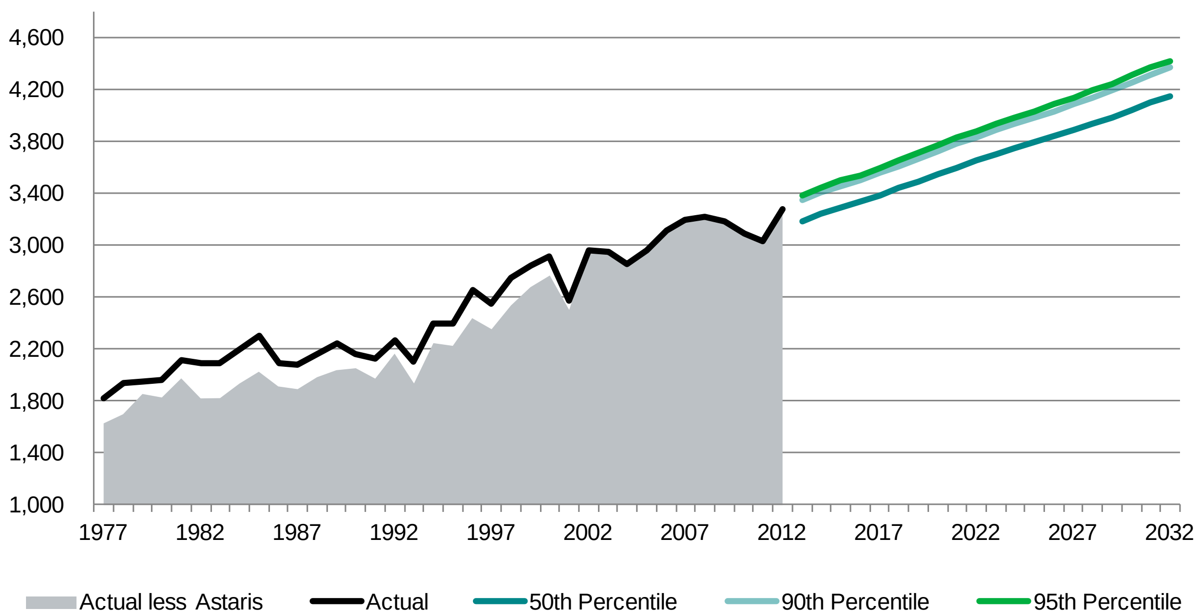

Figure 12. Forecast system summer peak (MW)

The all-time system winter peak demand was 2,528 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. As shown in Figure 13, the historical system winter peak load is much more variable than the summer system peak load. This is because the variability of peak-day temperatures in winter months is far greater than the variability of peak-day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 13 illustrates the higher variability associated with winter peak-day temperatures.

In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,585 MW in 2013 to 3,020 MW in 2032, an average growth rate of 0.8 percent per year over the planning period (Table 11). In the 95th-percentile forecast, the system winter peak load is expected to increase from 2,683 MW in 2013 to 3,118 MW in 2032, an average growth rate of 0.8 percent per year over the planning period (Table 11). The three scenarios of projected system winter peak load are illustrated in Figure 13.

Table 11. System winter peak load growth (MW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
95th Percentile	2,683	2,765	2,901	3,118	0.8%
90th Percentile	2,585	2,668	2,803	3,020	0.8%
50th Percentile	2,301	2,384	2,520	2,737	0.9%

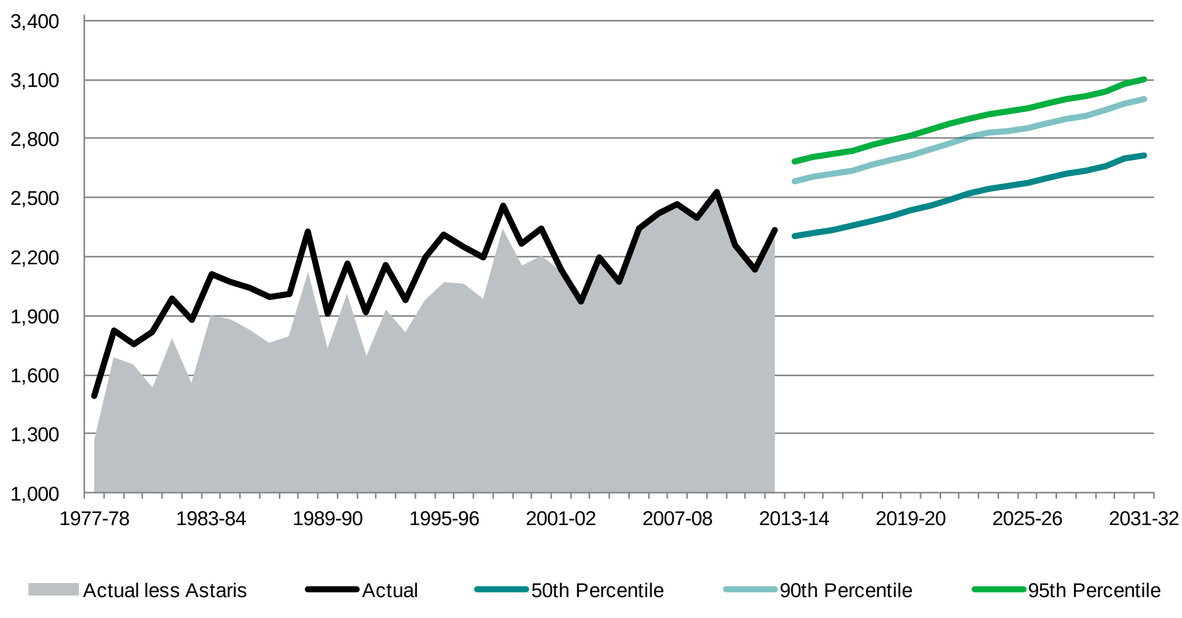

Figure 13. Forecast system winter peak (MW)

COMPANY SYSTEM LOAD

The system load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and on-system contracts (including past sales to Raft River and the City of Weiser). The system load excludes all long-term, firm, off-system contracts.

The expected-case system load forecast is based on the most recent Moody's Analytics economic forecast for the nation, state, MSAs, and counties in the service area and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 1.1 percent per year from 2013 to 2032. Company system load projections are reported in Table 12 and shown in Figure 14.

In the expected-case forecast, the company system load is expected to increase from 1,759 aMW in 2013 to 2,154 aMW in 2032. In the 70th-percentile forecast, the company system load is expected to increase from 1,800 aMW in 2013 to 2,201 aMW by 2032, an average growth rate of 1.1 percent per year over the planning period (Table 12).

Table 12. System load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
90th Percentile	1,872	1,959	2,078	2,284	1.1%
70th Percentile	1,800	1,884	2,000	2,201	1.1%
Expected Case	1,759	1,842	1,956	2,154	1.1%

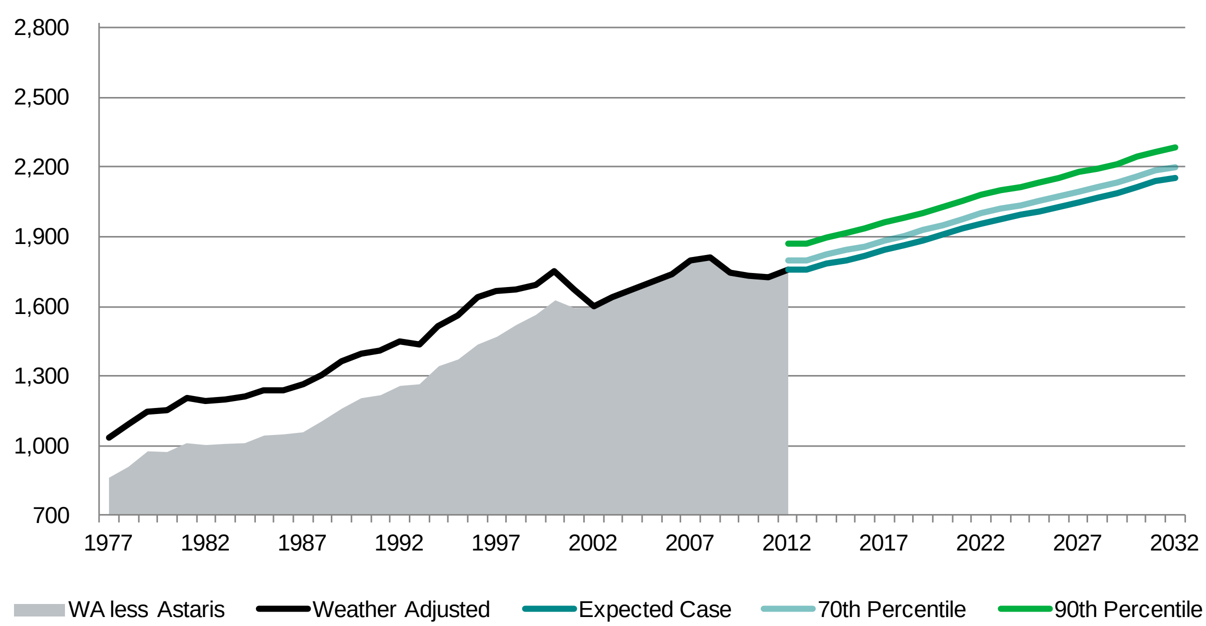

Figure 14. Forecast system load (aMW)

The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris has been Idaho Power's largest individual customer and, in some past years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. Without the dampening effects of Astaris on historical system load growth, the system load more accurately portrays the underlying general business growth trend within the service area.

Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, *Appendix A—Sales and Load Forecast* projects continued growth in Idaho Power's system load. Total load is made up of system load plus long-term, firm, off-system contracts. At this time, there are no contracts in effect to provide long-term firm energy off-system.

The composition of system company electricity sales by year is shown in Figure 15. Residential sales are forecast to be nearly 23 percent higher in 2032, gaining 1.1 million MWh over 2013. Commercial sales are also expected to be 23 percent higher or 0.9 million MWh above 2013 followed by industrial (38 percent higher or 0.9 million additional MWh) and irrigation (only 0.2 percent higher in 2032 than 2013). Electricity sales to Astaris ended in April 2002.

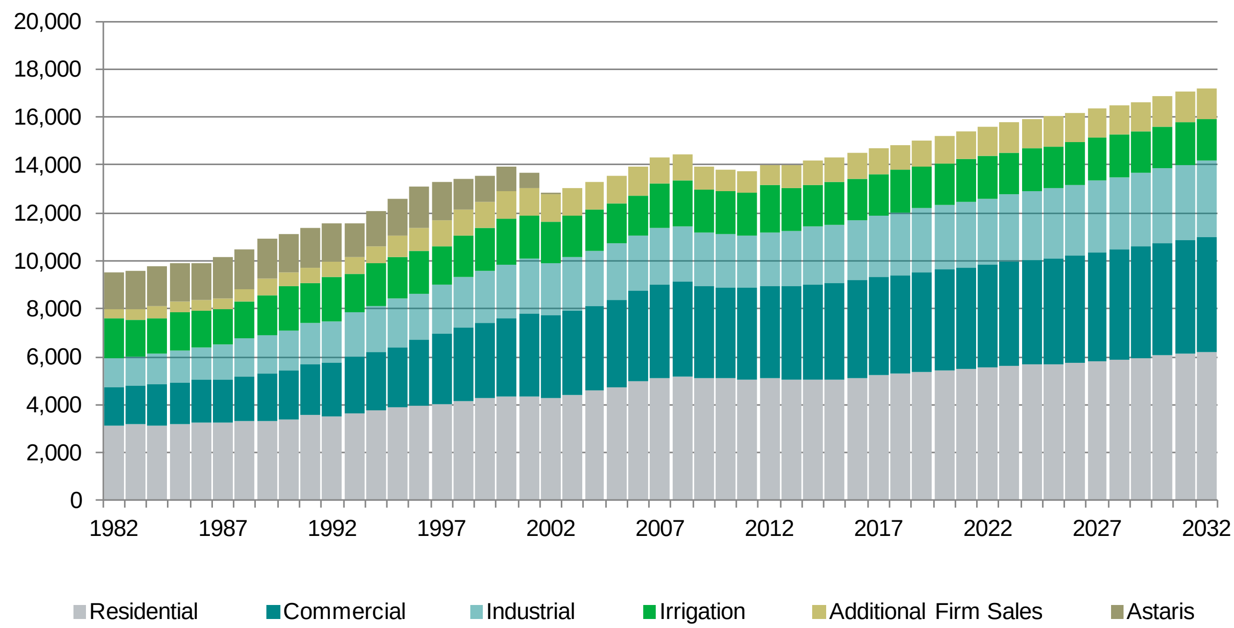

Figure 15. Composition of system company electricity sales (thousands of MWh)

The additional firm load category (which represents sales to Micron Technology, Simplot Fertilizer, and the INL) is forecast to grow by 24 percent from 2013 to 2032.

CONTRACT OFF-SYSTEM LOAD

The contract off-system category represents long-term contracts to supply firm energy to off-system customers. Long-term contracts are contracts effective during the forecast period lasting for more than one year. At this time, there are no long-term contracts.

The historical consumption for the contract off-system load category was considerable in the early 1990s; however, after 1995, off-system loads declined through 2005. As intended, the off-system contracts and their corresponding energy requirements expired as Idaho Power's surplus energy diminished due to retail load growth. In the future, Idaho Power may enter into additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

This page left blank intentionally.

ENERGY EFFICIENCY AND DEMAND RESPONSE

Energy efficiency and demand response impacts are treated differently in the forecasting and planning process. Energy efficiency impacts (reductions) are explicitly integrated into the forecast models. Demand response impacts are explicitly *excluded* from the forecast models; the impacts of demand response are modeled in the load and resource balance as a supply-side resource for reducing peak-demand periods.

Energy Efficiency

Energy efficiency influences on past and future load consist of utility programs, statutory codes, and manufacturing standards for appliances, equipment, and building materials that reduce energy consumption. As the influence of statutory codes and manufacturing standards on residential and commercial customers has increased in importance relative to utility programs, Idaho Power forecast models have been modified to ensure they capture these influences. Specifically, the models capture the physical flow of energy-efficient products through shipment data to resellers and installers. The source for this data is the DOE (the data also serves as input to the DOE NEM), and the data is refined by Itron for utility-specific applications. This data captures energy-efficient installations regardless of the source (e.g., programs, standards, and codes). However, Idaho Power closely monitors the assumptions and impacts of DOE data to ensure the model correctly captures all energy-efficiency impacts.

Efficiency data for industrial and irrigation customers is not directly surveyed and collected by the DOE; therefore, the models for efficiency impacts have been developed using a methodology established in Itron's white paper, "Incorporating DSM into the Load Forecast".[1] This approach develops statistical methods to recognize efficiency trends from historical utility acquisition, recognizing that historical trends are embedded in the actual sales data (which serves as the basis for the sector's forecast). Trends associated with future acquisitions from these existing programs (and their cumulative impacts) are similarly developed to compare with historical trends. If there is a significant change in future trends (i.e., trends unseen by the regression model of historical actual energy and conservation trends), the forecast output is adjusted to realize the trend change embedded in the regression output.

Regardless of the method, efficiency impacts from the models are compared to sister utility acquisitions to ensure the models are correctly capturing all energy savings.

Energy savings from energy efficiency programs are typically measured and reported at the point of delivery (customer's meter). Therefore, energy efficiency savings are increased by the amount of energy lost in transmitting the electricity from the generation source to the customer's meter.

---

[1] Stuart McMenamin and Mark Quan. *Incorporating DSM into the Load Forecast*. Itron, https://www.itron.com/na/PublishedContent/Incorporating%20DSM%20into%20the%20Load%20Forecast.pdf (accessed February 3, 2011).

The influence of new efficiency programs is not typically prepared in time to be available for input into the forecast models. Therefore, the impacts of the new programs are accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of existing and new energy efficiency and demand response programs is shown in the load and resource balance in *Appendix C—Technical Appendix*. In the next planning cycle, the impact of new committed programs will be considered when updating the individual class-level sales forecasts.

Demand Response

Beginning with the 2009 IRP, demand response programs have been accounted for in the load and resource balance. Demand response program data, including operational targets for demand reduction, program expenses, and cost-effective summaries, are detailed in *Appendix C—Technical Appendix*.

Demand response programs are treated as supply-side resources in the 2013 IRP and are not incorporated into the sales and load forecast. In the load and resource balance, the forecast of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply-side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. Because energy efficiency programs also result in a reduction to peak demand, there is a component of peak-hour load reduction integrated into the sales and load forecast. This provides a consistent treatment of both types of programs, as energy efficiency programs are considered in the sales and load forecast while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B—Demand Side Management 2012 Annual Report*.

Appendix A1. Historical and Projected Sales and Load

Residential Load						
Historical Residential Sales and Load, 1972–2012 (weather adjusted)						
Year	**Average Customers**	**Percent Change**	**kWh per Customer**	**Billed Sales (thousands of MWh)**	**Percent Change**	**Average Load (aMW)**
1972	145,208	–	10,959	1,591	–	184
1973	152,957	5.3%	11,537	1,765	10.9%	203
1974	160,151	4.7%	12,066	1,932	9.5%	223
1975	167,622	4.7%	12,955	2,172	12.4%	250
1976	175,720	4.8%	13,455	2,364	8.9%	271
1977	184,561	5.0%	13,686	2,526	6.8%	290
1978	194,650	5.5%	14,235	2,771	9.7%	321
1979	202,982	4.3%	14,779	3,000	8.3%	342
1980	209,629	3.3%	14,585	3,057	1.9%	348
1981	213,579	1.9%	14,339	3,063	0.2%	349
1982	216,696	1.5%	14,395	3,119	1.9%	356
1983	219,849	1.5%	14,375	3,160	1.3%	363
1984	222,695	1.3%	14,146	3,150	(0.3%)	357
1985	225,185	1.1%	14,049	3,164	0.4%	363
1986	227,081	0.8%	14,256	3,237	2.3%	368
1987	228,868	0.8%	14,097	3,226	(0.3%)	366
1988	230,771	0.8%	14,352	3,312	2.7%	378
1989	233,370	1.1%	14,336	3,346	1.0%	383
1990	238,117	2.0%	14,277	3,400	1.6%	393
1991	243,207	2.1%	14,566	3,542	4.2%	402
1992	249,767	2.7%	14,146	3,533	(0.3%)	408
1993	258,271	3.4%	14,172	3,660	3.6%	412
1994	267,854	3.7%	14,002	3,750	2.5%	434
1995	277,131	3.5%	14,004	3,881	3.5%	438
1996	286,227	3.3%	13,734	3,931	1.3%	455
1997	294,674	3.0%	13,682	4,032	2.6%	463
1998	303,300	2.9%	13,744	4,169	3.4%	476
1999	312,901	3.2%	13,620	4,262	2.2%	488
2000	322,402	3.0%	13,407	4,322	1.4%	500
2001	331,009	2.7%	13,160	4,356	0.8%	476
2002	339,764	2.6%	12,637	4,294	(1.4%)	488
2003	349,219	2.8%	12,653	4,419	2.9%	507
2004	360,462	3.2%	12,686	4,573	3.5%	524
2005	373,602	3.6%	12,684	4,739	3.6%	543
2006	387,707	3.8%	12,878	4,993	5.4%	568
2007	397,286	2.5%	12,924	5,135	2.8%	585
2008	402,520	1.3%	12,875	5,182	0.9%	594
2009	405,144	0.7%	12,672	5,134	(0.9%)	584
2010	407,551	0.6%	12,461	5,078	(1.1%)	582
2011	409,786	0.5%	12,363	5,066	(0.2%)	577
2012	413,610	0.9%	12,274	5,077	0.2%	581

Residential Load

Projected Residential Sales and Load, 2013–2032

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	417,852	1.0%	12,025	5,025	(1.0%)	574
2014	422,850	1.2%	11,954	5,055	0.6%	577
2015	429,685	1.6%	11,783	5,063	0.2%	579
2016	438,746	2.1%	11,695	5,131	1.3%	587
2017	448,379	2.2%	11,644	5,221	1.8%	597
2018	457,313	2.0%	11,588	5,299	1.5%	606
2019	465,250	1.7%	11,545	5,371	1.4%	614
2020	472,652	1.6%	11,480	5,426	1.0%	620
2021	479,844	1.5%	11,412	5,476	0.9%	626
2022	486,853	1.5%	11,363	5,532	1.0%	632
2023	493,741	1.4%	11,342	5,600	1.2%	640
2024	500,509	1.4%	11,294	5,653	0.9%	646
2025	507,171	1.3%	11,235	5,698	0.8%	651
2026	513,749	1.3%	11,230	5,769	1.2%	659
2027	520,202	1.3%	11,230	5,842	1.3%	667
2028	526,553	1.2%	11,199	5,897	0.9%	674
2029	532,781	1.2%	11,197	5,966	1.2%	682
2030	538,901	1.1%	11,211	6,042	1.3%	690
2031	544,944	1.1%	11,203	6,105	1.0%	697
2032	550,883	1.1%	11,189	6,164	1.0%	704

Commercial Load

Historical Commercial Sales and Load, 1972–2012 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1972	22,585	–	46,141	1,042	–	120
1973	23,286	3.1%	48,145	1,121	7.6%	128
1974	24,096	3.5%	49,028	1,181	5.4%	136
1975	25,045	3.9%	51,217	1,283	8.6%	147
1976	26,034	3.9%	52,513	1,367	6.6%	157
1977	27,112	4.1%	52,416	1,421	3.9%	162
1978	27,831	2.7%	52,476	1,460	2.8%	169
1979	28,087	0.9%	56,389	1,584	8.4%	180
1980	28,797	2.5%	54,145	1,559	(1.6%)	178
1981	29,567	2.7%	54,286	1,605	2.9%	184
1982	30,167	2.0%	54,127	1,633	1.7%	186
1983	30,776	2.0%	52,676	1,621	(0.7%)	186
1984	31,554	2.5%	53,383	1,684	3.9%	191
1985	32,418	2.7%	53,989	1,750	3.9%	201
1986	33,208	2.4%	53,869	1,789	2.2%	204
1987	33,975	2.3%	53,357	1,813	1.3%	206
1988	34,723	2.2%	54,409	1,889	4.2%	216
1989	35,638	2.6%	55,451	1,976	4.6%	227
1990	36,785	3.2%	55,844	2,054	3.9%	236
1991	37,922	3.1%	56,164	2,130	3.7%	243
1992	39,022	2.9%	56,339	2,198	3.2%	253
1993	40,047	2.6%	57,951	2,321	5.6%	263
1994	41,629	4.0%	58,181	2,422	4.4%	280
1995	43,165	3.7%	58,742	2,536	4.7%	288
1996	44,995	4.2%	62,048	2,792	10.1%	323
1997	46,819	4.1%	62,019	2,904	4.0%	333
1998	48,404	3.4%	62,722	3,036	4.6%	347
1999	49,430	2.1%	64,191	3,173	4.5%	363
2000	50,117	1.4%	65,975	3,306	4.2%	383
2001	51,501	2.8%	67,339	3,468	4.9%	383
2002	52,915	2.7%	64,788	3,428	(1.1%)	390
2003	54,194	2.4%	64,243	3,482	1.6%	399
2004	55,577	2.6%	64,042	3,559	2.2%	407
2005	57,145	2.8%	63,517	3,630	2.0%	415
2006	59,050	3.3%	63,425	3,745	3.2%	426
2007	61,640	4.4%	63,336	3,904	4.2%	445
2008	63,492	3.0%	62,200	3,949	1.2%	451
2009	64,151	1.0%	59,488	3,816	(3.4%)	436
2010	64,421	0.4%	58,820	3,789	(0.7%)	434
2011	64,921	0.8%	58,285	3,784	(0.1%)	432
2012	65,599	1.0%	58,941	3,866	2.2%	442

Commercial Load

Projected Commercial Sales and Load, 2013–2032

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	66,489	1.4%	58,657	3,900	0.9%	446
2014	67,430	1.4%	58,737	3,961	1.6%	452
2015	68,612	1.8%	58,249	3,997	0.9%	457
2016	70,122	2.2%	57,661	4,043	1.2%	462
2017	71,686	2.2%	56,953	4,083	1.0%	466
2018	73,199	2.1%	56,250	4,117	0.9%	470
2019	74,579	1.9%	55,754	4,158	1.0%	475
2020	75,873	1.7%	55,392	4,203	1.1%	480
2021	77,131	1.7%	55,025	4,244	1.0%	485
2022	78,357	1.6%	54,730	4,288	1.0%	490
2023	79,565	1.5%	54,520	4,338	1.2%	495
2024	80,754	1.5%	54,202	4,377	0.9%	500
2025	81,925	1.4%	53,864	4,413	0.8%	504
2026	83,082	1.4%	53,741	4,465	1.2%	510
2027	84,220	1.4%	53,642	4,518	1.2%	516
2028	85,343	1.3%	53,466	4,563	1.0%	521
2029	86,450	1.3%	53,429	4,619	1.2%	528
2030	87,540	1.3%	53,470	4,681	1.3%	535
2031	88,619	1.2%	53,491	4,740	1.3%	542
2032	89,685	1.2%	53,547	4,802	1.3%	549

Irrigation Load

Historical Irrigation Sales and Load, 1972–2012 (weather adjusted)

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1972	7,815	–	132,292	1,034	–	118
1973	8,341	6.7%	141,030	1,176	13.8%	134
1974	8,971	7.6%	147,698	1,325	12.6%	151
1975	9,480	5.7%	153,957	1,460	10.2%	167
1976	9,936	4.8%	155,406	1,544	5.8%	176
1977	10,238	3.0%	163,266	1,672	8.3%	191
1978	10,476	2.3%	154,006	1,613	(3.5%)	184
1979	10,711	2.2%	161,705	1,732	7.4%	197
1980	10,854	1.3%	155,740	1,690	(2.4%)	192
1981	11,248	3.6%	164,533	1,851	9.5%	211
1982	11,312	0.6%	151,369	1,712	(7.5%)	196
1983	11,133	(1.6%)	142,865	1,591	(7.1%)	182
1984	11,375	2.2%	132,933	1,512	(4.9%)	172
1985	11,576	1.8%	134,849	1,561	3.2%	178
1986	11,308	(2.3%)	134,121	1,517	(2.8%)	173
1987	11,254	(0.5%)	128,532	1,446	(4.6%)	165
1988	11,378	1.1%	137,237	1,561	7.9%	178
1989	11,957	5.1%	137,982	1,650	5.7%	188
1990	12,340	3.2%	146,128	1,803	9.3%	206
1991	12,484	1.2%	135,557	1,692	(6.2%)	193
1992	12,809	2.6%	140,744	1,803	6.5%	205
1993	13,078	2.1%	125,294	1,639	(9.1%)	187
1994	13,559	3.7%	130,325	1,767	7.8%	202
1995	13,679	0.9%	125,349	1,715	(3.0%)	196
1996	14,074	2.9%	123,944	1,744	1.7%	199
1997	14,383	2.2%	115,552	1,662	(4.7%)	190
1998	14,695	2.2%	114,918	1,689	1.6%	193
1999	14,912	1.5%	117,715	1,755	3.9%	200
2000	15,253	2.3%	126,625	1,931	10.0%	220
2001	15,522	1.8%	116,328	1,806	(6.5%)	206
2002	15,840	2.0%	110,674	1,753	(2.9%)	200
2003	16,020	1.1%	110,784	1,775	1.2%	203
2004	16,297	1.7%	108,574	1,769	(0.3%)	201
2005	16,936	3.9%	98,823	1,674	(5.4%)	191
2006	17,062	0.7%	97,105	1,657	(1.0%)	189
2007	17,001	(0.4%)	105,867	1,800	8.6%	205
2008	17,428	2.5%	109,360	1,906	5.9%	217
2009	17,708	1.6%	100,337	1,777	(6.8%)	203
2010	17,846	0.8%	99,895	1,783	0.3%	204
2011	18,292	2.5%	97,124	1,777	(0.3%)	203
2012	18,675	2.1%	103,703	1,937	9.0%	220

Irrigation Load

Projected Irrigation Sales and Load, 2013–2032

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	18,890	1.2%	92,719	1,751	(9.6%)	200
2014	19,142	1.3%	92,074	1,762	0.6%	201
2015	19,396	1.3%	91,204	1,769	0.4%	202
2016	19,645	1.3%	89,128	1,751	(1.0%)	199
2017	19,899	1.3%	87,928	1,750	(0.1%)	200
2018	20,152	1.3%	87,142	1,756	0.4%	200
2019	20,404	1.3%	86,281	1,760	0.2%	201
2020	20,655	1.2%	85,477	1,766	0.3%	201
2021	20,909	1.2%	84,582	1,769	0.2%	202
2022	21,160	1.2%	83,429	1,765	(0.2%)	202
2023	21,413	1.2%	82,407	1,765	0.0%	201
2024	21,664	1.2%	81,620	1,768	0.2%	201
2025	21,917	1.2%	80,447	1,763	(0.3%)	201
2026	22,172	1.2%	79,028	1,752	(0.6%)	200
2027	22,423	1.1%	78,263	1,755	0.2%	200
2028	22,675	1.1%	77,568	1,759	0.2%	200
2029	22,926	1.1%	76,458	1,753	(0.3%)	200
2030	23,180	1.1%	75,656	1,754	0.0%	200
2031	23,434	1.1%	75,013	1,758	0.2%	201
2032	23,684	1.1%	74,129	1,756	(0.1%)	200

Industrial Load

Historical Industrial Sales and Load, 1972–2012 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1972	56	–	10,944,714	615	–	71
1973	63	12.3%	10,889,056	687	11.7%	79
1974	65	2.2%	11,464,249	739	7.6%	84
1975	71	10.5%	11,014,121	785	6.1%	91
1976	73	3.0%	11,681,540	858	9.3%	99
1977	85	15.1%	10,988,826	929	8.3%	106
1978	99	17.6%	9,786,753	972	4.7%	111
1979	109	9.6%	9,989,158	1,087	11.8%	126
1980	112	2.7%	9,894,706	1,106	1.7%	125
1981	118	5.7%	9,718,723	1,148	3.9%	132
1982	122	3.5%	9,504,283	1,162	1.2%	133
1983	122	(0.3%)	9,797,522	1,194	2.7%	138
1984	124	1.5%	10,369,789	1,282	7.4%	147
1985	125	1.2%	10,844,888	1,357	5.9%	155
1986	129	2.7%	10,550,145	1,357	(0.1%)	155
1987	134	4.1%	11,006,455	1,474	8.7%	169
1988	133	(1.0%)	11,660,183	1,546	4.9%	177
1989	132	(0.6%)	12,091,482	1,594	3.1%	183
1990	132	0.2%	12,584,200	1,662	4.3%	191
1991	135	2.5%	12,699,665	1,719	3.4%	196
1992	140	3.4%	12,650,945	1,770	3.0%	203
1993	141	0.5%	13,179,585	1,854	4.7%	212
1994	143	1.7%	13,616,608	1,948	5.1%	223
1995	120	(15.9%)	16,793,437	2,021	3.7%	230
1996	103	(14.4%)	18,774,093	1,934	(4.3%)	221
1997	106	2.7%	19,309,504	2,042	5.6%	235
1998	111	4.6%	19,378,734	2,145	5.0%	244
1999	108	(2.3%)	19,985,029	2,160	0.7%	247
2000	107	(0.8%)	20,433,299	2,191	1.5%	250
2001	111	3.5%	20,618,361	2,289	4.4%	260
2002	111	(0.1%)	19,441,876	2,156	(5.8%)	246
2003	112	1.0%	19,950,866	2,234	3.6%	255
2004	117	4.3%	19,417,310	2,269	1.5%	259
2005	126	7.9%	18,645,220	2,351	3.6%	270
2006	127	1.0%	18,255,385	2,325	(1.1%)	265
2007	123	(3.6%)	19,275,551	2,366	1.8%	270
2008	119	(3.1%)	19,412,391	2,308	(2.4%)	261
2009	124	4.0%	17,987,570	2,224	(3.6%)	254
2010	121	(2.0%)	18,404,875	2,232	0.3%	254
2011	120	(1.1%)	18,586,468	2,229	(0.1%)	254
2012	115	(4.2%)	19,746,525	2,269	1.8%	260

Industrial Load

Projected Industrial Sales and Load, 2013–2032

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	116	0.9%	20,123,969	2,334	2.9%	267
2014	117	0.9%	20,531,410	2,402	2.9%	275
2015	118	0.9%	20,904,644	2,467	2.7%	282
2016	121	2.5%	20,855,283	2,523	2.3%	288
2017	121	0.0%	21,229,207	2,569	1.8%	294
2018	123	1.7%	21,215,736	2,610	1.6%	298
2019	124	0.8%	21,400,507	2,654	1.7%	303
2020	125	0.8%	21,591,980	2,699	1.7%	308
2021	126	0.8%	21,777,074	2,744	1.7%	314
2022	128	1.6%	21,782,963	2,788	1.6%	319
2023	130	1.6%	21,787,965	2,832	1.6%	324
2024	131	0.8%	21,953,791	2,876	1.5%	328
2025	131	0.0%	22,268,240	2,917	1.4%	333
2026	133	1.5%	22,264,535	2,961	1.5%	338
2027	133	0.0%	22,596,372	3,005	1.5%	343
2028	135	1.5%	22,573,943	3,047	1.4%	347
2029	136	0.7%	22,727,071	3,091	1.4%	353
2030	138	1.5%	22,713,855	3,135	1.4%	358
2031	139	0.7%	22,862,159	3,178	1.4%	363
2032	140	0.7%	23,014,399	3,222	1.4%	367

Additional Firm Sales and Load*

Historical Additional Firm Sales and Load, 1972–2012

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1972	284	–	32
1973	291	2.3%	33
1974	282	(2.9%)	32
1975	314	11.2%	36
1976	289	(8.1%)	33
1977	311	7.8%	36
1978	357	14.8%	41
1979	373	4.4%	43
1980	360	(3.5%)	41
1981	376	4.6%	43
1982	368	(2.4%)	42
1983	425	15.6%	49
1984	466	9.6%	53
1985	471	1.1%	54
1986	482	2.4%	55
1987	502	4.2%	57
1988	530	5.6%	60
1989	671	26.5%	77
1990	625	(6.9%)	71
1991	661	5.8%	75
1992	680	2.9%	77
1993	689	1.3%	79
1994	741	7.5%	85
1995	878	18.6%	100
1996	989	12.6%	113
1997	1,048	6.0%	120
1998	1,113	6.2%	127
1999	1,122	0.8%	128
2000	1,143	1.9%	130
2001	1,118	(2.1%)	128
2002	1,139	1.9%	130
2003	1,120	(1.7%)	128
2004	1,157	3.3%	132
2005	1,175	1.6%	134
2006	1,189	1.2%	136
2007	1,141	(4.0%)	130
2008	1,114	(2.4%)	127
2009	965	(13.4%)	110
2010	907	(6.0%)	104
2011	906	0.0%	103
2012	862	(4.8%)	98

*Includes Micron Technology, Simplot Fertilizer, INL, Hoku Materials, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

Additional Firm Sales and Load*

Projected Additional Firm Sales and Load, 2013–2032

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	1,010	17.1%	115
2014	1,025	1.5%	117
2015	1,053	2.7%	120
2016	1,053	0.1%	120
2017	1,062	0.8%	121
2018	1,060	(0.3%)	121
2019	1,068	0.8%	122
2020	1,115	4.4%	127
2021	1,193	7.0%	136
2022	1,229	3.0%	140
2023	1,234	0.4%	141
2024	1,231	(0.2%)	140
2025	1,234	0.2%	141
2026	1,228	(0.5%)	140
2027	1,228	0.0%	140
2028	1,217	(0.9%)	139
2029	1,212	(0.5%)	138
2030	1,268	4.6%	145
2031	1,262	(0.5%)	144
2032	1,257	(0.4%)	143

*Includes Micron Technology, Simplot Fertilizer, and the INL

Company System Load (excluding Astaris)

Historical Company System Sales and Load, 1972–2012 (weather adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1972	4,566	–	577
1973	5,040	10.4%	635
1974	5,461	8.4%	690
1975	6,012	10.1%	760
1976	6,422	6.8%	810
1977	6,858	6.8%	863
1978	7,174	4.6%	910
1979	7,776	8.4%	977
1980	7,773	0.0%	974
1981	8,043	3.5%	1,012
1982	7,994	(0.6%)	1,004
1983	7,991	0.0%	1,009
1984	8,095	1.3%	1,012
1985	8,303	2.6%	1,045
1986	8,382	0.9%	1,050
1987	8,462	1.0%	1,059
1988	8,839	4.5%	1,108
1989	9,237	4.5%	1,161
1990	9,544	3.3%	1,206
1991	9,744	2.1%	1,219
1992	9,985	2.5%	1,259
1993	10,163	1.8%	1,266
1994	10,628	4.6%	1,344
1995	11,030	3.8%	1,373
1996	11,390	3.3%	1,437
1997	11,688	2.6%	1,471
1998	12,151	4.0%	1,522
1999	12,472	2.6%	1,565
2000	12,895	3.4%	1,628
2001	13,037	1.1%	1,594
2002	12,771	(2.0%)	1,596
2003	13,030	2.0%	1,637
2004	13,327	2.3%	1,673
2005	13,568	1.8%	1,703
2006	13,909	2.5%	1,739
2007	14,346	3.1%	1,796
2008	14,460	0.8%	1,813
2009	13,917	(3.8%)	1,744
2010	13,789	(0.9%)	1,734
2011	13,762	(0.2%)	1,725
2012	14,011	1.8%	1,760

Company System Load (including Astaris)						
Historical Company System Sales and Load, (1972–2012) (weather adjusted)				Astaris Sales and Load (1972–2002) (weather adjusted)		
Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)	Astaris Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1972	6,385	–	794	1,819	–	207
1973	6,685	4.7%	832	1,645	(9.6%)	188
1974	7,104	6.3%	887	1,643	(0.1%)	188
1975	7,569	6.6%	946	1,557	(5.3%)	178
1976	7,997	5.6%	998	1,575	1.2%	179
1977	8,276	3.5%	1,033	1,418	(10.0%)	162
1978	8,716	5.3%	1,094	1,542	8.8%	176
1979	9,170	5.2%	1,144	1,395	(9.6%)	159
1980	9,286	1.3%	1,155	1,513	8.5%	172
1981	9,677	4.2%	1,208	1,634	8.0%	186
1982	9,548	(1.3%)	1,191	1,554	(4.9%)	177
1983	9,600	0.5%	1,202	1,610	3.6%	184
1984	9,796	2.0%	1,215	1,701	5.7%	194
1985	9,917	1.2%	1,239	1,614	(5.1%)	184
1986	9,935	0.2%	1,236	1,554	(3.7%)	177
1987	10,154	2.2%	1,262	1,692	8.9%	193
1988	10,474	3.2%	1,303	1,635	(3.4%)	186
1989	10,940	4.4%	1,365	1,703	4.2%	194
1990	11,149	1.9%	1,398	1,604	(5.8%)	183
1991	11,353	1.8%	1,412	1,609	0.3%	184
1992	11,555	1.8%	1,446	1,570	(2.4%)	179
1993	11,600	0.4%	1,438	1,437	(8.4%)	164
1994	12,048	3.9%	1,514	1,420	(1.2%)	162
1995	12,597	4.6%	1,561	1,567	10.4%	179
1996	13,079	3.8%	1,639	1,689	7.8%	192
1997	13,315	1.8%	1,666	1,628	(3.6%)	186
1998	13,424	0.8%	1,674	1,273	(21.8%)	145
1999	13,523	0.7%	1,691	1,051	(17.4%)	120
2000	13,949	3.1%	1,754	1,054	0.3%	120
2001	13,695	(1.8%)	1,673	658	(37.5%)	75
2002	12,782	(6.7%)	1,597	11	(98.3%)	1
2003	13,030	1.9%	1,637	0	(100.0%)	0
2004	13,327	2.3%	1,673	0	0.0%	0
2005	13,568	1.8%	1,703	0	0.0%	0
2006	13,909	2.5%	1,739	0	0.0%	0
2007	14,346	3.1%	1,796	0	0.0%	0
2008	14,460	0.8%	1,813	0	0.0%	0
2009	13,917	(3.8%)	1,744	0	0.0%	0
2010	13,789	(0.9%)	1,734	0	0.0%	0
2011	13,762	(0.2%)	1,725	0	0.0%	0
2012	14,011	1.8%	1,760	0	0.0%	0

Company System Load

Projected Company System Sales and Load, 2013–2032

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	14,020	0.1%	1,759
2014	14,205	1.3%	1,782
2015	14,348	1.0%	1,800
2016	14,502	1.1%	1,818
2017	14,684	1.3%	1,842
2018	14,842	1.1%	1,862
2019	15,011	1.1%	1,883
2020	15,208	1.3%	1,906
2021	15,426	1.4%	1,934
2022	15,603	1.1%	1,956
2023	15,769	1.1%	1,977
2024	15,905	0.9%	1,992
2025	16,025	0.8%	2,009
2026	16,176	0.9%	2,028
2027	16,348	1.1%	2,049
2028	16,483	0.8%	2,065
2029	16,640	1.0%	2,087
2030	16,879	1.4%	2,116
2031	17,043	1.0%	2,137
2032	17,201	0.9%	2,154

This page left blank intentionally.